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Geothermal Reservoir Assessment Based on Slim Hole Drilling

Volume 1: Analytical Method

Prepared by
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EPRI Leadership in Science and Technology

REPORT SUMMARY

Geothermal Reservoir Assessment Based on Slim Hole Drilling

Volumes 1 and 2

EPRI tested and documented slim hole drilling as a geothermal resource evaluation method. The results of this work confirm that lower cost reservoir evaluations can be performed using slim hole methods. On the basis of this report's probabilistic reservoir size estimate, the Kilauea East Rift Zone on the island of Hawaii could support 100–300 MWe of geothermal power capacity.

INTEREST CATEGORY

Renewable generation and fuels

KEYWORDS

Geothermal power plants
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BACKGROUND Utilities sponsoring geothermal power plant projects face financial risk and expense in finding and confirming reservoirs. A lesser, but important, risk involves underproduction and/or lower-than-design temperature from production wells drilled to deliver geothermal hot water to the power plant. Drilling and flow testing full-size production wells in advance of power plant construction is an expensive way to mitigate risks. The State of Hawaii and EPRI cosponsored the project reported here to use smaller, less-expensive "slim holes" as a means of discovering and evaluating a geothermal reservoir.

OBJECTIVE To test and document the slim hole method of geothermal reservoir assessment.

APPROACH The project team consisted of university researchers, a geothermal resource/reservoir assessment firm, and various suppliers of geothermal drilling and field-testing services. They planned and documented the slim hole method and its application to the Kilauea East Rift Zone (KERZ), the geothermal resource area of greatest near-term potential in Hawaii. Next, they designated a series of four slim holes, known as scientific observation holes (SOHs) 1, 2, 3, and 4. Using injection flows, they drilled and tested three of the four SOHs. Finally, they prepared this final report, documenting the method, the SOH experience, the results, and the conclusions of the Kilauea test.

RESULTS The Hawaii application confirms the viability of the slim hole approach. Specifically, the three holes drilled and tested suggest that costs can be reduced by half compared with a full-size well. In addition, the slim holes provided results consistent with an analysis based on a more complete data set. A probabilistic analysis of the variation in crucial geothermal reservoir parameters, as measured or estimated from SOH and other available data, led to a KERZ reservoir size estimate with the following probability distribution: a mean of 288 MWe, a mode of 180 MWe, and a standard deviation of 177 MWe. A probabilistic analysis using only data from the three SOHs provided similar results: a mean of 173 MWe, a mode of 100 MWe, and a standard deviation of 116 MWe. A 28-MWe commercial geothermal power plant is now located at this reservoir. The SOH-only analysis shows a 95% probability that the lower KERZ reservoir will support this plant's full capacity for 25 years.

The three holes drilled were 7.6 cm (3.0 in) in diameter at their narrow final depth. Drilled to total depths of 1.6–2.0 km (5526–6802 ft), the holes indicated reservoir temperatures ranging between 206–350°C (403–662°F). SOH-1 exhibited high flow capacity (6100 millidarcy-ft) behind a thin impermeable barrier that partially obscured the reservoir flow capacity. The other two holes exhibited low flow capacity (about 1330 millidarcy-ft). On the basis of flow capacity and the related permeability measurements, a rock porosity range of 3–7% was used in reservoir modeling. Volume 1 of this report contains the slim hole analytical method. Volume 2 describes its specific application to KERZ.

EPRI PERSPECTIVE The report shows how to proceed with a slim hole reservoir assessment project. The particular example of KERZ on the island of Hawaii offers more of a guide to reveal lessons learned than a model to be emulated. Costs were about twice as high as planned, but the project revealed methods of reducing costs that were successfully employed on the last of the holes (SOH-2). Costs to drill and complete the holes ranged from nearly $300/ft for SOH-1 at 5526 ft (1684 m) down to $160/ft for SOH-2 at 6802 ft (2073 m). With conventional industry completion practices and use of rotary drilling to the bottom of the hole (without recovery of core samples), costs as low as $100/ft could be targeted for 6500–6800 ft (2.0–2.1 km) deep slim holes. Full-size wells would cost $300–$400/ft in this depth range under Kilauea conditions.

PROJECT

RP1994-04

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ABSTRACT

The Hawaii Scientific Observation Hole (SOH) program was planned, funded, and initiated in 1988 by the Hawaii Natural Energy Institute, an institute within the School of Ocean and Earth Science and Technology, at the University of Hawaii at Manoa. Initial funding for the SOH program was $3.25 million supplied by the State of Hawaii to drill six, 4,000 foot scientific observation holes on Maui and the Big Island of Hawaii to confirm and stimulate geothermal resource development in Hawaii. After a lengthy permitting process, three SOHs, totaling 18,890 feet of mostly core drilling were finally drilled along the Kilauea East Rift Zone (KERZ) in the Puna district on the Big Island. The SOH program was highly successful in meeting the highly restrictive permitting conditions imposed on the program, and in developing slim hole drilling techniques, establishing subsurface geological conditions, and initiating an assessment and characterization of the geothermal resources potential of Hawaii - even though permitting specifically prohibited pumping or flowing the holes to obtain data of subsurface fluid conditions.

The first hole, SOH-4, reached a depth of 2,000 meters, recorded a bottom hole temperature of 306.1°C, and established subsurface thermal continuity along the KERZ between the HGP-A and the True/Mid-Pacific Geothermal Venture wells. Although evidence of fossil reservoir conditions were encountered, no zones with obvious reservoir potential were found. The second hole SOH-1, was drilled to a depth of 1,684 meters, recorded a bottom hole temperature of 206.1°C, effectively doubled the size of the Hawaii Geothermal Project - Abbott/Puna Geothermal Venture (HGP-A/PGV) proven/probable reservoir, and defined the northern limit of the HGP-A/PGV reservoir. The final hole, SOH-2, was drilled to a depth of 2,073 meters, recorded a bottom hole temperature of 350.5°C, and has sufficient indicated permeability to be designated as a potential "discovery".

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1. INTRODUCTION

1.1 Background and Objectives

This report presents the results of a project whose objectives are the definition and application of a methodology to characterize and assess geothermal reservoirs using information obtained and derived from the drilling of slim exploration holes. The assessment methodology is designed to form a central part of an overall strategy of geothermal resource exploration, investigation and assessment, leading ultimately to commercial development of the resource (figure 1.1). It is conceived primarily as a tool focusing on the characteristics of the geothermal reservoir that affect the economic feasibility of development.

The definition and application of the slim hole assessment methodology has been integrated with the execution of a program of scientific slim hole drilling within the Kilauea East Rift Zone (KERZ) on the island of Hawaii. This program so far includes the drilling and testing of three slim holes up to 6,000 feet deep in an area that has undergone geothermal exploration and development, including the drilling of deep wells, over the past decade. Prior to and during the drilling phase, specifications were provided by GeothermEx for drilling, logging, testing and other information gathering activities within the slim hole drilling program, based on the requirements and objectives of the assessment methodology.

Volume I of this report is a description and definition of the assessment methodology. In Volume II, the methodology is applied to the KERZ using the data collected from the slim holes completed to date.

The remainder of this section of Volume I discusses the objectives, structure and products of the methodology as an overview of the assessment model. In section 2 the mathematical and theoretical background of the model is discussed.

Sections 3 and 4 discuss the data obtained from slim hole drilling and testing that are essential or useful as inputs to the model. Section 3 emphasizes the needs of the model, and in section 4 the procedures used for gathering data from drilling, testing and logging operations are reviewed.

Section 5 discusses in detail the estimation or derivation of critical resource parameters from the slim hole data or from other parameters, and describes the methodology that utilizes the estimated resource parameters to derive a probabilistic model of the geothermal system's resource capacity, a model that serves as the basis for economic feasibility studies (figure 1.1). Section 6 illustrates the application of the slim hole methodology by presenting a brief hypothetical case, from the planning and drilling stage through the estimation of field capacity.

1.2 Description of the Model

Assessment of the economic feasibility of commercial development of a geothermal field requires that the rate and amount of energy that can be economically extracted from the field be estimated. Any improvement in the reliability and precision of this estimation that can be obtained by collecting new or better data, or improving techniques of analysis, results in a better ability to plan and carry out a development program and manage the resource over the long term. In many cases, it can also increase the likelihood of obtaining project financing by providing a sounder basis for forecasting project economics.

A wide variety of surface techniques have been applied to geothermal exploration, including, predominantly, geological, geophysical, and geochemical survey methods. Some of these have been found to be useful in identifying and locating potentially viable geothermal prospects in the form of commercially drillable hydrothermal systems. Shallow drilling, primarily to measure temperature gradients, is also commonly used. However, none of these methods provides the direct evidence of the presence and quality of a commercial geothermal resource that serves to confirm a geothermal discovery, or constitute the basis for a valid estimation of field capacity or recoverable reserves. For these, direct knowledge of reservoir fluid enthalpy (as indicated by measured reservoir temperatures and pressures, for single-phase reservoirs, or direct measurement for 2-phase reservoirs) reservoir permeability and related parameters (allowing determination of well performance), and, in many cases, reservoir fluid chemistry, is necessary. This information has traditionally come from deep, large-diameter wells drilled with the intention of producing fluid at commercial rates if they are successful.

Larger-diameter wells provide some advantages when employed in the initial stage of deep drilling, in that they can allow direct measurement of well capacity, and in some cases can be retained as commercial production or injection wells when and if the field is developed. However, these advantages typically are offset in large part not only by the relatively high cost per well, but also by a tendency of early wells to be rendered useless due to damage, improper completion (due to inadequate knowledge of reservoir geometry and conditions), or inappropriate location.

An alternative to using large-diameter wells as the first step in a deep-drilling program is to carry out a carefully planned program of drilling smaller diameter wells, or "slim holes". Such a program may have a number of advantages, including:

- Relatively low cost per hole, allowing more reservoir volume to be explored for a given drilling budget.

- Most of the same information obtained from large-diameter wells is obtained.

- A wider variety of drilling equipment can be used, including smaller rotary rigs, reverse-circulation rotary rigs, and core-drilling rigs. This often allows access to more terrain, with less surface impact.

- Planning, permitting, preparation and execution of drilling activities typically can be carried out in a shorter period of time.

- Completed slim holes can provide a valuable source of reservoir monitoring information during field development and operation.

Because of its relatively low cost, slim hole drilling can also be considered a substitute for or complement to geophysical or geochemical surveys in the initial exploration stage, particularly in areas where such surveys have proven to be ineffective. For example, in the Cascade geological province, geophysical and geochemical surveys have proven unsatisfactory as geothermal exploration tools because of the presence of a thick overburden of rocks cooled by the heavy precipitation typical of that region (the so-called "rain curtain"). The relative scarcity of hot springs, fumaroles and other surface manifestations of geothermal energy in this active volcanic belt testifies to the influence of the rain curtain. Slim hole drilling as an exploration tool may be used in the Cascades to "pierce" the rain curtain, and the drilling of relatively costly full-diameter wells postponed until a reservoir below the rain curtain is identified.

A similar rain curtain has frustrated geothermal exploration in the island of Hawaii even though well-defined volcanic rift zones are known to localize geothermal systems. It is heartening, therefore, that the University of Hawaii, through the support of EPRI, has embarked on a slim hole drilling program to supplement the meager knowledge about the geothermal prospects at Hawaii in spite of the years of geophysical exploration. In fact, as reviewed in the second volume of this report, the 3 slim holes drilled to date by the University have already substantially improved the knowledge about the geothermal prospects at the Puna rift zone, where a commercial geothermal development is underway.

The criteria that distinguish slim holes from large-diameter wells are not necessarily fixed; there may be overlap between the two categories depending on field and drilling conditions. The primary distinction is that a slim hole is drilled with the expectation that the wellbore diameter will be insufficient for commercial production if the well is successful. Normally this will mean that the diameter of the open-hole stage of the well will be 6-1/4 inches or less, and may be as small as the smaller standard core diameters (around two inches).

To be useful as a tool in resource exploration and estimation, a slim hole should be designed to allow, at a minimum, downhole logging using temperature, pressure, spinner and geophysical logging tools, under static conditions and while injecting water. Preferably downhole sampling of fluids should also be possible, as should flowing of the well if it intercepts a productive zone. Drilling of the hole should be planned to allow collection of as much information as possible during drilling (for example, recovery of cuttings or cores), but not to the exclusion of any of the above.

Figure 1.1 shows the role of slim hole drilling and assessment in an idealized program of resource exploration and development. Although other studies may continue concurrently, a slim hole program should follow and be planned on the basis of a program of surface and shallow exploration, which in turn is based on a set of clearly defined project objectives. This initial exploration and investigation should provide sufficient information to carry out the following:

- Selection of the most attractive prospect or prospects within the areas or region considered.

- Identification and delineation of the area to be investigated by drilling.

- Prioritization of drilling sites.

- Determination of physical and regulatory constraints on slim hole drilling.

- Preliminary design of slim holes, and estimation of drilling objectives and conditions based on a preliminary geologic model of the area.

- Estimation of the number of holes required for adequate assessment of the resource.

As mentioned before, slim hole drilling may be a part of the initial exploration program, even before a geothermal reservoir is identified. Therefore, in figure 1.1, the "Review of Existing Data" phase of the assessment program may include some slim hole data. However, unless otherwise stated, slim hole drilling in this report is not considered a part of the initial exploration program.

Any or all of these parameters are, of course, subject to significant revision once the slim hole drilling program is underway. However, their careful assessment before drilling begins will allow the best possible allocation of budget and other resources, and also will serve to clarify whether the resources can be adequately assessed given available funding. As indicated in figure 1.1, the level of additional commitment of expenditure associated with proceeding to the slim hole drilling phase requires that a decision be made based on the surface investigations as to whether to continue the exploration program. If the decision is yes, funds should be committed to carry out sufficient drilling to reach the stage of economic feasibility assessment.

Adequate planning of the slim hole drilling program is of critical importance to the quality of the eventual assessment of the resource. Ideally, the plan for drilling should be detailed enough to eliminate unnecessary expenditure of time and money in reassessing drilling objectives once the program is underway, but flexible enough that the results of the earlier holes can guide the location and design of the later ones. Also, procedures for data collection and testing should be well planned and elaborated, so that necessary equipment and personnel can be available when needed to prevent the loss of critical information.

The dashed rectangle in figure 1.1 encloses the phases of activity that constitute the slim hole based resource assessment methodology that is the subject of this volume. When applied to an adequately planned and executed slim hole drilling program, the methodology provides an assessment of the resource that is sufficient to carry out an economic feasibility analysis of a single or multiple development and operating scenarios. Because the methodology is based on probabilistic techniques, taking into account the level of uncertainty imposed on resource estimation by the abundance or lack of available information, it allows specified levels of confidence to be used as criteria for accepting or rejecting the resource as economically viable. Sophisticated economic modeling, including forecasting of cash flow conditional on resource characteristics, can therefore be included within the feasibility study stage.

Confidence levels and uncertainty criteria can also be used as a basis for choosing to carry out additional slim hole drilling, with re-application of the assessment methodology, if necessary to provide the level of information necessary to proceed to the feasibility stage. As figure 1.1 shows, this process can be iterative, potentially including multiple phases of drilling and assessment before a feasibility study is undertaken.

Figure 1.2 shows a more detailed view of the assessment methodology, proceeding from the drilling stage through the stages of data reduction, analysis and estimation to the eventual assessment of resource capacity. Table 1.1 lists and describes the relationships between the various data categories, methods of analysis, and resource parameters that are the critical elements in the assessment process. These illustrations are discussed in general terms here, and in greater detail in subsequent sections.

Once the slim hole drilling program has been fully planned, permitted and budgeted, drilling begins and along with it the collection of data important to the assessment process (see sections 3 and 4). As holes are completed, the more comprehensive stage of data collection involving downhole logging, injection testing, and, if possible, flow testing and chemical sampling begins. Ideally the logging and testing stage, with preliminary processing of data obtained therefrom, should be carried out as soon as possible in order to evaluate any potential impact on the planning of remaining drilling. In any case, the testing phase will continue once all holes have been drilled, until all critical information has been collected (table 1.1, first column).

A variety of data reduction and analysis techniques are applied to the slim hole data once collected, constituting the first phase of the assessment process. These include compilation of graphical downhole summaries of well data, construction of subsurface maps and cross sections displaying geological and reservoir characteristics, analysis of well test data to determine well and reservoir response characteristics, and chemical analysis of fluid samples with compilation and graphical display of analytical data.

The initial phase of data reduction and analysis leads to the estimation of primary resource parameters (table 1.1, column 3). These are the basic physical parameters that define and describe the size and properties of the geothermal reservoir. They include:

- Reservoir area: the extent of surface area underlain by extractable reserves of geothermal heat.

- Reservoir thickness: the vertical thickness of rock containing extractable heat reserves.

- Reservoir depth: the distance from the ground surface to the top of the commercial reservoir.

- Temperature distribution: the three-dimensional distribution of temperature within the area under study, and particularly within the reservoir volume. Of particular interest for assessment purposes is the average temperature within the reservoir volume.

- Pressure distribution.

- Fluid chemistry: the chemical composition of the reservoir fluids, including concentrations of ionic species, dissolved noncondensible gases, and others.

- Rock density: the distribution and average density of the rock matrix within the reservoir volume.

- Rock porosity: distribution and average value.

- Specific heat or heat capacity of the rock matrix.

- Reservoir flow capacity: the permeability-thickness characteristic (commonly expressed as kh) calculated on the basis of well test data.

An important feature of this classification of resource parameters is that the reservoir or resource volume is defined on the basis of extractable heat at sufficient commercial temperature, and does not require that commercially productive wells be drillable at all locations. Therefore the available reserves may include reservoir volume of permeability too low for commercial drilling, but susceptible to extraction of heat by wells drilled into nearby, more permeable intervals. The degree to which more or less heat may be extracted is taken into account in the reserves assessment process by a recovery factor parameter, estimated on the basis of a number of primary resource parameters.

The primary resource parameters may be treated as quantities that vary in three dimensions when necessary for certain types of analysis and modeling, or as average quantities over the reservoir volume, which is useful for estimation of overall reserves. In either case, the knowledge of these parameters derived from the information obtained from a suite of slim holes is inevitably imperfect, and therefore is associated with some degree of uncertainty. The level of uncertainty is dependent both on the density and quality of the slim hole data and other, and on the heterogeneity of the reservoir.

The uncertainty of a particular resource parameter at any point in the reservoir, or as an average quantity, may be characterized as a probability distribution, that is, as a frequency function that represents, for each possible value, the likelihood that the parameter in question has that value. The probability distribution for each parameter can be modeled as one of a number of standard functions, with a specific mean, standard deviation, and other statistical properties. Section 2 discusses the theoretical basis for selecting functions to characterize the various resource parameters, and section 5 describes procedures for defining their probability distributions.

The use of probability distributions to describe resource parameters allows the uncertainty of each parameter to be used in the process of assessing energy reserves, through the use of probabilistic methods. This is advantageous as a tool for economic evaluation, because it allows the estimate of energy recoverable from the resource to be expressed itself as a probability distribution, and therefore the likelihood of any particular level of reserves being present can be estimated quantitatively. As a result, the risk/reward potential of any development scenario can be evaluated.

In addition to the data obtained directly from the slim holes, the estimation of primary resource parameters, and also all subsequent assessment phases, make use of several categories of information external to the slim hole program. The first of these categories is the information and preliminary model of the resource developed during the stage of surface or shallow exploration. While the data obtained in the surface stage do not directly measure any reservoir parameters, they can provide useful guidance in defining and limiting parameter distributions. For example, surface geologic mapping may aid in estimating reservoir area by identifying the trend and position of structures such as faults that, based on the drilling data, may be known to form impermeable barriers to flow and therefore create natural boundaries to the reservoir. Surface characteristics of lithology and structure may also provide a guide to subsurface heterogeneity, influencing the estimation of such parameters as porosity, density and reservoir depth. Chemical geothermometry applied to hot springs or fumaroles, while not supplying a direct measurement of reservoir temperature, may prove useful in estimating maximum temperatures that might be encountered in undrilled areas.

A second category of auxiliary information can be described as statistical information from previously explored and developed geothermal fields. This can be a formal compilation of information from other fields, but more commonly may be simply the experience of the specialists carrying out the assessment process. As an example, an assessment of a geothermal system in a terrane of active andesitic volcanism may be expected to have substantially different characteristics (in terms of temperature, reservoir geometry, and permeability) than a non-volcanic system in the basin and range province of the United States. Knowledge of the typical characteristics of systems in the terrane under study may be used to supplement the specific data obtained from the slim holes when estimating resource parameters. Obviously, care must be taken to give priority to drilling data and avoid unrealistic estimations based on personal bias.

Theoretical data comprise a third category of auxiliary information that may play a role in parameter estimation. Examples include: limitations on reservoir temperatures and pressures imposed by the thermodynamic properties of water; limits on rock densities and specific heat given the known properties of possible mineral assemblages; and limits on well performance based on the laws of fluid dynamics.

Estimation of a more complex set of resource and reservoir performance parameters comprises the next phase of the assessment process (table 1.1, column 4). A number of these are derived in a relatively straightforward manner from the primary resource parameters, by mathematical combination or extension of the primary parameter distributions. Such parameters include the overall reservoir volume; the reservoir fluid content, volumetric specific heat and overall heat content; fluid enthalpy and density; and the distribution of permeability.

Other parameters require either more complex estimation methods or knowledge of production well and perhaps even power plant characteristics. Most important of these is the energy recovery factor, which is dependent on a variety of reservoir characteristics. Estimation of a specific group of these parameters requires the use of wellbore and reservoir simulation techniques. This group includes forecasted well flow rates and enthalpies, well spacing and overall drilling requirements.

The final stage in the assessment methodology generates estimates of fieldwide reserves of recoverable energy, and forecasts of field performance under one or more development and operating scenarios. Forecasting field performance in detail requires the use of numerical reservoir simulation techniques (table 1.1, column 5), which are beyond the scope of this report. Depending on the abundance and quality of information from the slim holes, it may be possible by numerical simulation to generate forecasts of reservoir temperature and pressure changes over time, well productivity decline rates and infill drilling requirements (table 1.1, column 6).

Energy reserves may be estimated by one of several methods. In this report we present a probabilistic methodology that yields probability distributions of recoverable reserves and related parameters. The background of this methodology is discussed in section 2, and section 5 describes its application. Using this technique, it is possible to estimate overall reserves of recoverable energy, the field capacity, and field lifetime at a variety of confidence levels (table 1.1, column 6). These constitute the most important resource data used in subsequent stages of economic feasibility assessment.

2. MATHEMATICAL BACKGROUND

2.1 Data Reduction Procedures

A variety of techniques may be applied to the interpretation of data from slim holes. The procedures that may be used encompass interpretation of downhole temperature, pressure and geophysical logs; statistical analysis of chemical data; analysis of well test results including pressure transients; and three-dimensional modeling of reservoir parameters such as temperature and subsurface geology. Judgement and experience are essential in selecting and applying these techniques.

Recommended procedures for processing slim hole data are reviewed in section 4. Because of their diversity no theoretical review is given here.

2.2 Models of Resource Parameter Probability Distributions

All resource parameters, such as reservoir temperature, porosity, and depth, must be estimated from a limited set of data, and are therefore incompletely constrained even in densely drilled areas. As noted earlier, the uncertainty in estimating, for example, average reservoir temperature is a function of both the data density (the number of available holes with temperature measurements) and of the heterogeneity of the temperature within the reservoir volume. It may in some cases also be affected by data quality factors; in the case of temperature there may be wellbore effects that obscure the true temperature profile in most wells, making even direct temperature measurements uncertain.

Due to this uncertainty, any estimated parameter may have a variety of possible outcomes over some range, even though it may be possible to select a most likely outcome as the best estimate. Each parameter may therefore be characterized by a probability function that expresses the likelihood or probability of occurrence of each possible outcome as a relative frequency. Figure 2.1 shows an example of one such distribution, in which reservoir temperature is modeled as a simple rectangular function. In the rectangular distribution, each possible outcome within a defined range has an equal relative likelihood or probability. In other words, figure 2.1 expresses the notion that the average reservoir temperature may have any value in the range of 240 to 260°C, none more likely than another. There is no "most likely" value, but the distribution has a mean value that is simply the midpoint between the limits of the range.

A probability distribution may have any form that can be expressed as a function. However, there is ample basis to model the distributions of all resource parameters using a limited set of standard functions.

Many natural phenomena have frequency distributions that can be modeled by the Gaussian function, also called the normal distribution. This function has the familiar bell-curve shape (figure 2.2), and is expressed by the equation:

$$f(x) = \frac{1}{\sqrt{2\pi}} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2} \tag{2.1}$$

The normal distribution has a most-likely or peak value μ, which is also the mean value. Other outcomes fall off symmetrically above and below this central value. The width of the curve is defined by σ, which is the standard deviation of the distribution. Although the normal distribution function is defined to infinity in both directions, more than 95% of outcome probability occurs within one standard deviation of the mean, and 99.7% is enclosed by two standard deviations either side of the mean (figure 2.2).

The normal distribution is a convenient and accurate means of modeling the probability distributions of many resource parameters, particularly those that can be characterized by a best estimate or most likely value, and are "open-ended", that is, not strongly constrained either on the high or low end, so that possible outcomes may vary more or less freely in either direction. For example, if a reasonable quantity of temperature information is available, it will be possible to determine a most likely value for average reservoir temperature, so that the probability distribution of temperature can be modeled as a normal distribution (figure 2.3) instead of the rectangular distribution shown in figure 2.1. In the absence of compelling evidence constraining the temperature more on the high end than the low, or vice versa, the frequency of possible outcomes will tend to decrease symmetrically in each direction. The width of the distribution will be determined by the degree to which the possible temperature outcomes are constrained by the available data; the standard deviation σ can be estimated based on the estimated 95% confidence interval.

Phenomena which are strongly constrained on one end of the outcome range often exhibit a lognormal behavior (figure 2.4), in which the logarithm of possible outcomes has a normal distribution:

$$f(x) = \frac{1}{\sqrt{2\pi}} e^{-\frac{1}{2}\left(\frac{\ln x-\mu}{\sigma}\right)^2} \qquad (2.2)$$

This type of distribution may be illustrated using reservoir thickness as an example. A number of holes may penetrate a small distance into the top of the reservoir (as identified by temperatures above the designated reservoir cutoff temperature), thereby strongly constraining the lower limit of possible thickness, which in any case cannot be lower than zero. However, if no holes completely penetrate the reservoir interval, as is commonly the case, then the upper limit of reservoir thickness is much more open-ended or poorly constrained, so that relatively high probabilities continue over a range of higher possible outcomes (figure 2.5).

The lognormal distribution has a peak or most likely value of e^{μ}. Because of the asymmetry of the distribution, however, this is not also the mean, as in the normal distribution. The lognormal distribution is simple in that, like the normal distribution, it can be defined by two parameters, μ and σ, but it is computationally and conceptually more difficult.

Probability distributions of resource parameters can often be satisfactorily represented using a simpler function, the triangular distribution (figure 2.6). This function has the form of a triangle defined by vertices a, b, and c that represent the most likely, minimum and maximum outcomes, respectively. The triangular distribution can be expressed by:

$$f(x) = \begin{cases} \dfrac{2(x-b)}{(a-b)(c-b)} & \{b \le x \le a\} \\ \dfrac{2(c-x)}{(c-a)(c-b)} & \{a < x \le c\} \end{cases} \tag{2.3}$$

This function has several advantages over the normal and lognormal distributions. Most importantly, it can easily be visualized in terms of the familiar concepts of minimum, maximum and most likely, and therefore probability distributions can be characterized rapidly on the basis of a few simple criteria. Computationally it is relatively simple to manipulate, and so it can be used readily in a variety of modeling methodologies. Also, by varying the position of the most likely value relative to the minimum and maximum, the distribution can be made asymmetrical, approximating the lognormal distribution as well as the normal distribution if desired (figure 2.7).

A rectangular distribution may be appropriate for some parameters, especially those that are so poorly constrained by data availability or other considerations that there is no reliable basis for estimating a most likely value. Figure 2.8 shows the form of the rectangular distribution, which is defined simply by its upper and lower limits, a and b. The distribution is therefore expressed as the function:

$$f(x) = \frac{1}{b-a} \quad \{a \le x \le b\} \tag{2.4}$$

In some cases other functions may be more appropriate to describe the probability distributions of certain parameters. For example, some distributions may be bimodal, having two peaks representing two outcomes that are more likely relative to surrounding outcomes. Such a case could occur, for instance, in a reservoir dominated by two different rock types, with distinctly different porosities, present in an unknown proportion. The probability distribution of average reservoir porosity might, in the extreme case, have two peaks corresponding to the estimated most likely porosities of both rock types (figure 2.9). In practice, however, it is preferable to avoid this type of complexity for computational reasons.

2.3 Computation with Probability Distributions

When resource parameters are represented by probability distributions, quantities derived from the basic parameters must be calculated using their distribution functions. As a result, secondary parameters derived from the primary resource parameters have their own distribution functions. For simple algorithms that combine simple probability functions, analytical solutions may be possible, but such solutions are more complex than they may seem at first. For example, consider calculation of reservoir volume from reservoir area and thickness, when both area and thickness are represented by triangular distributions. It might appear that the probability distribution of reservoir volume can be derived by multiplying the corresponding parameters a, b and c (most likely, minimum and maximum values) from the area and thickness distributions. In fact, the correct resulting distribution, although it approximates the triangular function, has a non-triangular shape, broadening near the peak and narrowing near the base. As combinations of probability distributions become more complex, the deviations from simple functions become more pronounced.

A convenient and versatile means of avoiding such analytical problems is to use a numerical method to combine probability distributions. A simple and useful technique for this is to repeatedly sample the distributions using independent random numbers, applying the combination algorithm to the sample outcomes, and computing a histogram of the resulting values. The histogram derived in this way can then be used numerically to represent the distribution function as a series of frequencies for discrete outcome intervals, or used as the basis for selecting an analytical function to represent the distribution. This random-sampling method of combination is the basis for the Monte Carlo method of reserves estimation, discussed below.

Figure 2.10 illustrates the use of the random-sampling method of combining two distributions. In this figure, two triangular distributions have been combined by multiplication, using 50,000 random samplings from the two distributions, and plotting the results as a smooth histogram of 500 points. As figure 2.10 shows, the resulting distribution, although roughly triangular, begins to take on some of the characteristics of a normal distribution, with a broadened peak, and contraction of the curve near its base.

2.4 Pitfalls in the Use of Probability Distributions

A number of statistical problems may occur in using probability distribution functions for resource assessment methodology. The two most significant of these are problems of distinction of population and probability distributions, and independence of parameters.

It is important in applying the probabilistic methods discussed here to distinguish the population, or physical distribution of a parameter in space from the parameter's probability distribution. For example, reservoir temperature will vary naturally from point to point within the reservoir volume. If each point in the reservoir could be sampled and the results plotted in histogram form, the histogram would show the distribution of temperature in the reservoir. It is often possible to estimate this distribution from much more limited sample data (e.g. from temperatures measured in a number of wells). However, this distribution is distinct from the probability distribution of temperature at a single point, or averaged over some specified volume. The latter distribution represents the range and characteristics of uncertainty in estimation of the temperature of a point or volume, rather than the variation of temperature over space.

Population and probability distributions may closely resemble each other in shape and range. However, it is important to keep them logically separate when carrying out a reservoir assessment. As a reservoir becomes better sampled by more drilling, the estimated population distribution of a parameter such as temperature is likely to become broader (with a higher standard deviation), because additional sampling reveals more reservoir heterogeneities. At the same time, the probability distribution associated with estimating the temperature at any point or volume will become narrower with more sampling, because the estimation uncertainty is reduced. Therefore, while the population distribution of a parameter can provide useful information in estimating its probability distribution, it is important to conceptually separate the two.

The assessment methodology presented here is based on an assumption that the parameters used in calculation of reserves and other quantities are statistically independent of each other; that is, that a change in outcome of one parameter at a point or over the entire reservoir does not affect the outcome of any other parameter. This independence allows the parameters to be estimated separately and recombined in a statistically valid manner.

The primary resource parameters shown in table 1.1 have been selected in such a way as to provide a maximum of statistical independence. Still, a limited degree of interdependence is always present, and in some situations it may become important.

For example, consider a reservoir that has a regular and well-defined vertical temperature gradient, with temperature increasing steadily with depth. Any increase in average estimated reservoir thickness (due to recoverability of heat from greater depths) will tend to create an increase in average reservoir temperature, because the reservoir includes a greater proportion of deeper and therefore hotter material. Both the population and probability distributions of reservoir thickness and temperature are therefore statistically related to some degree.

The problem of statistical interdependence is difficult to treat mathematically and, in practice, can generally be ignored for this methodology without a significant impact on results. The problem should kept in mind, however, and each reservoir under study examined for possible severe interdependence effects that might tend to bias estimation of reserves.

2.5 A Probabilistic Approach to Estimation of Recoverable Energy Reserves

Quantitative estimation of recoverable energy reserves, that is, of the energy that is available for commercial extraction from a geothermal reservoir, depends on calculations involving a number of the resource parameters shown in table 1.1. To the degree that these parameters are imperfectly known, there will be uncertainty in any estimate of reserves. Ideally it is desirable not only to calculate a best estimate of the available reserves, but also to characterize as quantitatively as possible the uncertainty associated with the estimate. Most importantly, it is useful to be able to estimate the possible range of values of energy reserves, and the likelihood of occurrence of any particular value within the range. In other words, it is useful to know the probability distribution of recoverable energy reserves.

The reserves calculation method presented here is a means of estimating the probability distribution of reserves using the estimated probability distributions of other parameters. The model for reserves calculation is based on standard and widely accepted methods for geothermal resource assessment. The use of probability distributions in the calculation is based on the numerical technique for combining distributions (often known as the Monte Carlo Sampling Method) discussed in section 2.3.

The reserve estimation algorithm is based on a volumetric approach. It uses, with some modifications, the volumetric reserve estimation method introduced by the U.S. Geological Survey (Brook *et al.*, 1978).

In this method, the maximum sustainable power plant capacity (E) is given by:

$$E = AhC_v(T-T_0)\cdot R/F/L \qquad (2.5)$$

where A = areal extent of the reservoir,
h = thickness of the reservoir,

C_v = volumetric specific heat of the reservoir,

T = average temperature of the reservoir,

T_0 = rejection temperature (equivalent to the average annual ambient temperature),

R = overall recovery efficiency (the fraction of thermal energy in-place in the reservoir that is converted to electrical energy at the power plant),

F = power plant capacity factor (the fraction of time the plant produces power on an annual basis), and

L = power plant life.

The parameter R can be determined as follows:

$$R = \frac{W \cdot r \cdot e}{C_f \cdot (T - T_0)} \tag{2.6}$$

where r = recovery factor (the fraction of thermal energy in-place that is recoverable as thermal energy),

C_f = specific heat of reservoir fluid,

W = maximum available work from the produced fluid, and

e = utilization factor to account for mechanical and other losses that occur in a real power cycle.

The parameter C_v in (2.5) is given by:

$$C_v = \rho_r\, C_r\, (1-d) + \rho_f C_f\, d \tag{2.7}$$

where ρ_r = density of rock matrix,

C_r = specific heat of rock matrix,

ρ_f = density of reservoir fluid, and

d = reservoir porosity.

The parameter W in (2.6) is derived from the First and Second Laws of Thermodynamics as follows:

$$dW = dq\ (1 - To/T), \text{ and} \tag{2.8}$$

$$dq = C_f dT \tag{2.9}$$

where q represents thermal energy.

All of the parameters in the above equations that are not constrained by physical laws, or arbitrarily selected from economic or other criteria, have their own probability distributions that may be used as part of the estimation process. In practice, some parameters are found to have such narrow distributions that it acceptable to consider them as fixed quantities. These considerations are discussed further in section 5.

As discussed in section 2.3, to construct a joint probability distribution based on the reserves equations, using the probability distributions of individual parameters, is impractically complex by analytical methods. A practical method of constructing a joint probability distribution function is that of Monte Carlo simulation. The Monte Carlo simulation technique is a sampling procedure whereby highly complex expressions involving one or more probability distributions may be evaluated easily. In essence, it consists of simulating a process, such as the estimation of the reserves in a geothermal field, using a random sampling of the uncertain input parameters.

The basic method of Monte Carlo simulation for resource assessment can be best outlined as a series of steps as follows:

1. Estimate the range and distribution of possible values of each parameter that will affect the estimate of E. This process is described in section 5.

2. From the distribution of each parameter, select at random one value. This is usually done on the computer by using a random-number generator. Compute the values of E using this combination of values of the parameters. This determines one point in the final distribution of the values of E. Select at random a second value from the distribution of each of the parameters. Again, compute the resulting value of E. This is the second point in the distribution of values of E.

3. Repeat the process again and again, each time with the set of values selected at random from the distribution of each parameter. Enough combinations of parameter values should be considered to describe adequately the shape and range of the distribution of the values of E. Typically, several hundred such simulation runs are necessary. Mathematical methods are available for judging the adequacy of the number of simulation runs.

4. The calculated values of E can be arranged in the form of a distribution to determine the probability of obtaining various ranges of values of E; or by rearranging, on a cumulative frequency basis, the probability of obtaining at least a specific value of E can be estimated. Figure 2.11 is a schematic representation of the above procedure.

Sections 5 and 6 discuss further details and the application of the Monte Carlo method of reserves estimation. It is important to note that no probabilities are estimated subjectively in these reserves computations. All of the judgment went into the original definition of the distribution of the uncertain parameters. Calculations past that point were performed merely to keep track of the computed value of the reserves after each simulation run.

Mathematical solutions to risk assessment are exceedingly complex in most real-world situations. The Monte Carlo simulation technique circumvents these complexities without sacrificing statistical rigor. The nature of exploration risks can be estimated by Monte Carlo simulation even when the theoretical solution to the problem is unknown or is mathematically intractable. Basically, Monte Carlo simulation allows repeated random sampling of values between the boundaries of the range that have been specified. Although the solution generally will not be mathematically exact, it will very closely approach an exact solution if many samples are taken. Only the time required for the repetitive estimates and the supply of non-repeating random numbers impose constraints on the possible accuracy of the method.

3. DATA REQUIREMENTS

3.1 Introduction

This section reviews the types of data that should be collected from slim holes and outlines recommended methods of data reduction and analysis. Section 4 discusses in detail the methods of acquiring various types of data, including data collected during drilling, heat-up and well testing.

3.2 Specific Data to be Collected

The drilling process, and concurrent and subsequent logging and testing, produce many different types of data. Some data may be more or less direct measurements or samplings of resource parameters of interest (*e.g.* formation temperature), whereas others (*e.g.* drilling penetration rate, geophysical logs) are much more indirect and are useful for interpretation only in conjunction with other data. Types of information that should be collected routinely are:

- Primary rock lithology, based on petrographic examination of cores or drill cuttings.

- Hydrothermal alteration characteristics.

- Drilling penetration rate.

- Drilling fluid temperature.

- Bottomhole temperatures and pressures.

- Location of circulation loss zones.
- Measurements of water levels throughout the drilling process and after well completion.
- Measurements of static subsurface temperature and pressure.
- Sampling and analysis of reservoir fluids.
- Results of geophysical logging.
- Production test or injection test data, including production or injection rates and well productivity or injectivity indexes.
- Temperature, pressure and spinner surveys run while the well is shut in, flowing or while fluid is being injected.
- Pressure transient data, collected during changes in production or injection rate, and/or during the build-up or fall-off periods at the end of the test period.
- Pressure monitoring data from observation wells ("interference data").
- Tracer test data.
- Chemical samples collected during flow tests or using downhole sampling equipment.

3.3 Data Analysis

3.3.1 Downhole Data

Measurements and observations made at various depths or continuously in a drillhole permit interpretation of subsurface conditions at or near the wellbore. Interpretation of downhole data is best carried out by graphically plotting the different data as a function of depth. Such data include:

- Well design (casing sites and depths, liner type and depth, open hole diameter).
- Locations of major and minor losses of circulation during drilling.
- Steam or water entries encountered during drilling.
- Lithology.
- Drilling penetration rate.
- Wellbore flow patterns deduced from spinner surveys.
- Temperature and pressure data, including drilling fluid return temperatures and bottomhole temperature measured during drilling, and any temperature or pressure surveys run during drilling and after completion.

Other types of downhole data that may be examined in the same way include: gas data, such as methane or carbon dioxide (if gas concentration data are collected during drilling); hydrothermal alteration data (texture, mineralogy, etc.); water levels; geophysical logging data; and any other data that may help to interpret subsurface conditions in the reservoir.

Once such data have been graphically profiled, relationships between many of the parameters can be identified. There may be correlations between:

- Drilling penetration rate and lithology.
- Temperature and circulation losses.
- Temperature and fluid entries.
- Temperature and completion details.
- Circulation losses or fluid entries and spinner data.
- Numerous other downhole parameters.

Once these relationships are determined, data can be examined in three dimensions within and near the reservoir volume, using the knowledge of data interrelationships to extend the range of sparse information. Typically, temperature contour maps are made for several levels above, within and below the reservoir. Other information commonly displayed as level maps and cross sections include lithology, alteration, pressures or water levels, and deduced permeable zones. These representations form the basis for the analysis of resource parameters at individual points, over limited areas or volumes, or over the entire reservoir. As such, they constitute the framework for the conceptual hydrogeological model of the geothermal system.

3.3.2 Chemical Data

A wide variety of fluid chemical data may be accumulated from slim holes by analysis of fluids collected during flow testing or by downhole sampling. Such data are commonly interpreted and incorporated into the conceptual model of the system, and also may be used in the investigation of a number of specific problems or aspects of field development or operation, such as plant design, scale control, and reservoir performance monitoring. As a result, it is desirable to sample and analyze fluids as routinely as possible, in order to build a coherent chemical data base.

Data that should routinely be obtained by chemical analysis include concentrations of major and minor ionic species (*e.g.* Cl, Na, Ca, SiO_2, carbonate and sulfate species, among others), and concentrations of dissolved noncondensible gases (primarily CO_2 and H_2s). Isotopic compositions of hydrogen and oxygen, and possibly other elements, may be of interest for modeling purposes.

The evaluation of geochemical data for reservoir analysis involves comparative and quantitative procedures. Comparative procedures include tabulating data for fluids characterization and plotting key parameters on graphs, maps, and cross-sections. Examples of plots are:

- B vs. Cl;

- Na/K versus total dissolved solids;

- Non-condensible gas concentration versus enthalpy or wellhead pressure;

- Cl versus enthalpy; and

- SiO_2 versus enthalpy.

The quantitative procedures are divided into two stages. The first stage is the data reduction, which includes correcting from wellhead to reservoir conditions and entering the data into a computer database. The second stage is calculation of fluid condition at various points. This starts with chemical geothermometry to estimate fluid temperature in the reservoir; these results are then compared with measured temperature.

Depending upon data abundance, data quality and fluid characteristics, the second stage may or may not continue with estimations of silica and carbonate scaling potential, and gas partitioning during boiling and steam separation.

3.3.3 Well Test Data

If possible, production testing should be conducted for each slim hole that can flow by itself. A production test usually implies flowing of a well and recording the flow rate and pressure as functions of time. Ideally, either flow rate or pressure should be held constant. These data are then interpreted to estimate some characteristics of the reservoir. Ideally, the temperature of the fluid and its chemistry should also be monitored as functions of time. The well is flowed at a fixed rate until the fluid pressure has stabilized (a few hours). Then the flow rate is increased and held constant until a new, lower level of stabilized pressure is reached. This is repeated several times. This is called a deliverability test. Following such a test, the flow rate is held constant for a longer time (several hours to several days) and the gradual decline in pressure due to this flow is monitored. This is called a drawdown test. Finally, when the well is shut-in at the end of drawdown test, the resulting build-up in pressure is monitored. This is called a build-up test.

An injectivity test consists of injecting water into a productive well and monitoring fluid injection rate, pressure and temperature in the borehole. Temperature and pressure logs are often run in the borehole while injection is in progress. At the end of the test, injection may be stopped and the fall-off in pressure with time recorded. This constitutes an injection fall-off test.

A multi-rate test is akin to a drawdown or injectivity test conducted at several fixed flow rates in succession. A multi-well or interference test consists of flowing from or injecting in one well and observing the pressure response in nearby shut-in wells (observation wells). In some cases the pressure response in observation wells are recorded while more than one well is being flowed or injected into. Samples of water (or steam condensate) and non-condensable gases are sometimes collected during a production test and analyzed.

Well Test Interpretation

For hot water wells, deliverability data are plotted as wellhead pressure versus flow rate and the data points are joined by a smooth curve, from which one can estimate the flow rate to be expected at a given well pressure, or vice versa. For steam reservoirs, well deliverability data are plotted as the difference of the squares of the static and flowing pressures in the well versus flow rate on a log-log plot, and a straight line is defined.

There are three approaches to drawdown, buildup and interference test analysis: plotting on semilog graph paper, type-curve matching on log-log graph paper, and numerical simulation. The first two methods are relatively simple but assumes idealized reservoir conditions. The most common approach assumes a horizontal, radial, isothermal flow in an isotropic, uniform porous medium with only one fluid phase present (either water or steam but not both). Obviously this is far from reality in many reservoirs. The first approach is thus limited in application. The type-curve matching approach can be applied over a wider range of reservoir conditions. The numerical simulation approach is the most versatile but requires considerable computation and can be expensive.

There are two popular semilog plotting techniques to analyze a pressure buildup test: the Horner plot and the Miller-Dyes-Hutchinson plot (MDH plot). The Horner plot consists of plotting the measured pressure against the Horner dimension less time function, $(t+\Delta t)/\Delta t$, where t is the total flow time during the test and Δt is the time since shut-in. In the MDH plot, the shut-in pressure is plotted as a function of build-up time (Δt). Figure 3.1 is an example of an MDH plot.

Both Horner and MDH plots should show a linear trend, the slope being inversely proportional to the reservoir transmissivity, which can be calculated from the plot. In reality, these plots rarely show a single linear trend because of the difference between the ideal reservoir and/or well condition and the reality. For example, figure 3.1 shows a linear trend in only a portion of the data. Usually the deviation of the early-time data from straight line is caused by well damage or stimulation and wellbore storage effect. From this deviation, the relative effect of wellbore damage or stimulation (quantified as "skin factor") can be calculated.

The deviation of the late-time data from the straight line may be caused by the presence of a reservoir boundary, natural recharge, multiple feed zones, etc. The oscillatory trend of late-time data on figure 3.1 is due to the presence of two feed zones. If the late-time data show a smooth trend, it is usually possible to estimate the average pressure if the shape of the well drainage area relative to well location is known.

Earlougher (1977) presents details of these graphical techniques. By a similar semi-log plotting one can analyze drawdown data. For steam reservoir, the above procedures and type-curve matching remain the same except that the pressure data are handled in terms of pressure-squared or a "pseudo-pressure" (Mannon and Atkinson, 1977).

The type-curve matching techniques use a set of "type curves," which are plots (on log-log paper) of mathematical solutions of the transient flow problem under various sets of idealized reservoir and well conditions (Theis, 1935). The procedure is to plot the interference test data as the difference between the static and observed pressures versus time on a log-log plot and match this plot by trial-and-error to one of the type-curves. Once a match is obtained one can calculate flow capacity and storativity of the reservoir from the plot (Earlougher, 1977).

Although less commonly used, type-curve matching is equally applicable to drawdown and buildup. A large number of type-curves have been published in the literature, each essentially representing a departure from the restrictive ideal conditions listed before. Figure 3.2 shows an example where drawdown data are matched to a type-curve representing transient flow to the wellbore through an infinite-conductivity vertical fracture. From such a type-curve, it is potentially possible to estimate the length of the fracture.

Figure 3.3 is an example of an interference test where the data showed poor match to the conventional type-curve representing idealized flow conditions. Since this reservoir was controlled by a single large fault, a linear flow solution type-curve was generated to represent this flow. The match of the data to the linear flow solution is obvious from the figure.

Sometimes, complete type-curve matching is not critical, as long as certain trends are evident on a log-log plot. For example, a linear trend in the early-time data may indicate a fracture if the slope is 0.5, or wellbore storage effect if the slope is unity. For example, figure 3.4 is the log-log plot of build-up data from a well at The Geysers. No linear trend was evident when plotting the original data because of a suspected wrong record of the flowing pressure before shut-in. A correction procedure was developed and the data replotted as shown. Replotting revealed evidence of wellbore storage and fracture. From these trends on the log-log plot, it is possible to identify the true linear trend on the Horner or MDH plots.

Interpretation of injection tests can be handled exactly as for production tests because injection can be considered negative production. One has to resort to numerical simulation if the ideal conditions (with all variations that can be handled by type curves) do not exist in a reservoir. Typical problems where numerical simulation is called for are: nonisothermal flow, the presence of two phases (steam and water), extreme heterogeneity, fluctuating production or injection history, several wells producing and injection at different times, etc. Many of these problems, however, can be handled approximately by graphical techniques.

4. DATA SOURCES

4.1 Introduction

In section 3, the data required to assess a geothermal resource from slim hole drilling and a brief description of the analytical methods typically used were presented. This section describes the sources of these data in further detail, and presents methods of collection that have been found to be useful in developing quantitative models of geothermal reservoirs.

This section divided into three sections that follow the normal sequence of events: the drilling phase, the period of well heat-up, and the well testing phase. Some activities, such as the collection of downhole pressure and temperature data, occur during all three phases.

4.2 Data Collected During Drilling

The data to be collected as the well is drilled are summarized below. Most of these data are typically incorporated into a continuous, complete record, often referred to as the mud log. Originally, the mud log was used to record the parameters that affected the drilling fluid used and actual changes in drilling fluid as the hole progressed. Currently, the mud log is used to record many other parameters, including:

- Detailed descriptions of drill cuttings or cores, including primary lithologic variations, hydrothermal alteration mineralogy, rock texture on both microscopic and macroscopic scales, and identification of potentially permeable zones, veins or fractures.

- Bottomhole temperatures, as recorded using maximum reading thermometers. These should be measured at a convenient interval, and are often measured when directional surveys are made to determine the drift of the well.

- The temperature of the drilling fluid (mud, aerated mud, foam, water or air) as it circulates into and out of the hole. This should be monitored and recorded at a regular interval, such as every ten feet.

- Drilling penetration rate, in units such as feet per hour. Significant drilling breaks (zones of very high penetration rate) should be noted, as they may represent permeable zones.

- The location of circulation losses, including the depth at which they are encountered, the volume of fluid lost, and if the loss is total or partial.

- The location of fluid entries into the wellbore during drilling.

- The concentrations of various chemical constituents in the drilling fluid circulating out of the well, including gases and individual species (*e.g.*, Cl) which may help in locating productive zones.

- Static water levels, which can be used to identify the potential of different aquifers encountered in the well. These are typically measured after any circulation loss or detected fluid entry, or at any time when there is a drilling delay (waiting on parts, etc.).

- Directional surveys, which are made at the intervals specified in the drilling program. Even if a vertical well is planned, directional surveys are often made every several hundred feet or so to ensure that the well has not drifted from vertical.

- Changes in drilling fluid composition, including fluid type, density and additives.

- Hole diameters and depths, casing points and casing diameters.

- The points at which any logs are run, cores made, downhole fluid samples collected, or well tests conducted.

The mud log is completed gradually as the well is drilled, often by a company that specializes in mud logging services. Upon completion, the pages of the log are spliced together and a "master" original is made. From this original, numerous copies can be made. The value of the mud log cannot be emphasized enough. It is a record of the well made by an unbiased yet skilled person, and preserves information that can be collected only during the drilling process.

Geophysical logs may be run at one or more times during drilling or at the time the hole is completed. There are two main uses for geophysical logs: 1) to evaluate the physical condition of a well (*e.g.*, using caliper or cement bond logs); and 2) to decipher the geologic structure of a geothermal field. There are many types of logs that apply to the second category including a wide variety of electrical and radioactive logs. Suites of logs to be run, it any, should be chosen based on considerations of rock types, reservoir conditions, and specific objectives of identification or correlations.

The most common type of log that may be run during drilling is the downhole temperature and pressure log. While it is unlikely that equilibrium temperature conditions will be established during the drilling process, permeable zones may be identified by running temperature surveys. There may be appropriate times to run such surveys, *e.g.*, during a break in the drilling while waiting on parts, or during a brief well test conducted while the drilling rig is in place ("rig test").

Rig tests are typically carried out after a significant fluid entry or circulation loss has been encountered. The purpose of a rig test is to quickly estimate the productivity or injectivity of the hole, and to make a decision about drilling (*e.g.*, to stop, continue, or modify the drilling program). If fluid samples are collected, chemistry can also be evaluated.

There are other opportunities to collect fluid samples during the drilling process. Samples can be collected while air drilling if there is production of water or steam to the surface, during mud/water drilling if circulation is suspended and the hole is allowed to flow, and during any kind of drilling if the hole is unloaded by swabbing or bailing. The samples are likely to carry suspended solids and may require being centrifuged before filtration and acidification. Suspended carbonates can dissolve when dirty samples are acidified.

Drilling mud chemistry may be monitored to detect reservoir fluids by correlating changes in ion concentrations and ratios with reservoir fluid entry points. Parameters of particular interest are mud resistivity, Cl and HCO_3.

4.3 Data Collected During Heat-Up

After completion, the hole is thoroughly cleaned out to remove any rock particles or drilling mud and filled with fresh water. Gradually, the wellbore heats up until it is in equilibrium with the surrounding rock.

Typically, numerous downhole temperature and pressure surveys are run during this heat-up period. It may take a month or more before stabilized surveys can be obtained; without the surveys run during the heat-up period, it is difficult to determine if equilibrium has been reached. Stabilized temperature and pressure surveys are among the most important data that can be collected from any geothermal well.

Although uncommon in most commercial geothermal projects, downhole fluid samples can be collected during the heat-up period using a special tool which opens at a predetermined time or on command after being lowered to the desired sampling depth. Samples obtained from selected depths may help to define interzonal flow when the well is shut in; however, this can be more readily accomplished using spinner surveys.

Spinner surveys are often run in tandem with pressure and temperature surveys; hence, they are often referred to as PTS surveys. A spinner is a device that rotates in the presence of moving fluid, with the speed of rotation being proportional to the relative fluid velocity. The relative velocity of the fluid is in turn dependent on the internal configuration of the wellbore, the velocity of the spinner tool up or down the hole, and the strength of any feed zones in the hole. As such, spinner surveys are used to identify permeable zones and the relative contribution of each to the total flow. When run under shut-in conditions, a spinner survey is typically used to identify zones of upflow or downflow in the wellbore, which are often seen as long isothermal sections on downhole temperature surveys. If upflow or downflow is occurring, the true temperature profile can be masked; therefore, spinner surveys can help to decipher downhole temperatures.

4.4 Data Collected During Testing

Well test data are particularly important for reservoir characterization and quantification. After the hole is completed and the drilling fluid has been circulated out and replaced with water, a short-term injection test is often carried out by pumping fresh water into the well. This type of test, whose primary purpose is to demonstrate the presence of permeable zones, often precedes the heat-up period. Alternatively, a brief production test may be conducted, which not only demonstrates the productivity of the well but can help to shorten the heat-up period by flushing hot reservoir water through the region surrounding the well and through the wellbore itself. In either case, various types of data are collected during these tests, as summarized below.

- Downhole temperature, pressure and spinner surveys are run during production or injection to identify permeable zones.

- Wellhead and downhole pressures are measured and recorded during flow or injection to estimate the productivity or injectivity index of the hole. Wellhead pressure is typically monitored using a gauge; downhole pressure can be monitored using a Kuster type tool.

- Production or injection rate and wellhead temperature are measured and recorded. If the well produces two-phase fluid, flow rate cannot be determined without an elaborate test set-up; therefore, only the liquid portion of the flow is typically measured during this type of test.

- Downhole pressure changes, between rate steps or at the end of the production or injection period, are measured using a Kuster tool or capillary tubing. These data are used for pressure transient analysis to determine skin factor, transmissivity and storativity.

- If the well is produced, at least one chemical sample is collected.

Once the short-term flow test or injection test has been completed, the well is typically allowed to heat up as described in the previous section, and preparations are made to conduct a long-term production or injection test. During this type of test, subsurface pressures may be monitored in nearby holes, in which case it is termed an interference test.

The primary difference between a short-term and a long-term test is that for the latter a more elaborate test set-up is required to monitor flow rate and downhole conditions. First, downhole capillary tubing should be installed in the active well and, if possible, in one or more observation wells to monitor subsurface pressures precisely over time. Second, the equipment and instrumentation required to accurately determine flow rates, particularly for two-phase wells, are quite complex.

Essentially, the same data are collected during a long-term injection test as during a short-term injection test; however, the well is typically tested at several different rates and allowed to stabilize fully at each rate. If observation wells are used, they must be instrumented appropriately to record downhole pressures before, during and after the test period. Additional data to be collected during a long-term production test are:

- Downhole temperature, pressure and spinner surveys, to evaluate the location and relative contribution of various permeable zones.

- Stabilized wellhead and downhole pressure at each flow rate, to estimate the productivity index of the well.

- Wellhead temperature and pressure, lip pressure, water level at a weir (alternatively, the differential pressure across an orifice plate and the orifice upstream pressure), and any other data necessary to calculate the flow rate and enthalpy of the produced fluid.

- Downhole pressure buildup following the flow period, to determine skin factor, transmissivity and storativity using pressure transient analysis techniques.

- Downhole pressure in observation wells during the periods of production and pressure recovery.

In addition, chemical samples are typically collected during each rate step. Fluid samples can be obtained from single phase and two phase flow lines at wells and separators. Steam samples are condensed under pressure to collect condensate and non-condensible gases together or separately. Water samples are cooled during collection to prevent boiling. Liquid and steam in a two-phase flow are typically separated and sampled individually, under pressure. Water samples after steam separation at atmospheric pressure are obtained at points of discharge such as the flowline from the well into the drilling sump (*e.g.*, the blooie line), or the weirbox. Samples should be treated as appropriate (*e.g.* by acidification, dilution, etc.) to preserve unstable species for analysis.

Whenever samples are collected, the physical conditions related to the state of the fluid are recorded. These include:

- recent history of the well (drilling, production test, injection, repairs, known or suspected damage, most recent logs, etc.);

- wellhead temperature and pressure (gauge and absolute);

- flow rate;

- total flow enthalpy (if measured);

- collection method and sample source (port location, weirbox, depth downhole, etc);

- temperature and pressure (gauge and absolute) of steam separation and sample collection;

- downhole temperature at the production zone(s);
- depth of downhole sample collection and temperature at that point; and
- date and time of sample collection.

Some of this information usually is recorded somewhere in the drilling or testing program, but interpretation of chemical data is often hindered by the difficulty of accessing and compiling it from different sources. Hence, such information is typically recorded and filed alongside the chemical data.

For most purposes the most important species and properties to be analyzed are:

- in liquids - As, B, Ca, Fe, K, Li, Mg, Na, NH_4, SiO_2, Cl, HCO_3-CO_3, F, SO_4, pH and conductivity;
- in steam condensates - Na, Cl, HCO_3-CO_3, B and pH; and
- in gases - CO_2, H_2S, CH_4, N_2, O_2, H_2, NH_3 and (if equipment allows) Ar.

Analyses of trace metals (e.g., Hg, Cr, Ni, Pb) may be needed to meet environmental or other regulatory requirements. Stable isotopes of hydrogen and oxygen should be analyzed in water and steam condensate which has been collected at the same pressure, at a commercial laboratory with good reputation in the geothermal industry.

5. ANALYTICAL AND COMPUTATIONAL PROCEDURES

5.1 Data Reduction: Preparation for Assessment

Procedures for data collection, reduction and preliminary analysis during and following the drilling of slim holes were reviewed in sections 3 and 4. Before the reservoir assessment process begins, the data reduction and analysis phase should be carried out such that the following compilations of information are at hand, to the extent permitted by the available slim hole data:

- Petrographic descriptions of cores or cuttings, including detailed description of lithology and alteration, particularly of the rocks within the geothermal reservoir.

- Summary lithologic and alteration columns for all slim holes.

- Maps and cross sections of subsurface geology, as appropriate.

- Plots of downhole temperature, pressure and spinner survey results versus depth, for surveys performed under static and flowing conditions.

- Plots of other downhole parameters versus depth, including drilling penetration rate, drilling fluid temperatures, bottomhole pressures, and geophysical logs, as available.

- Contour maps and, if necessary, cross sections showing the subsurface distribution of temperature and pressure.

- Graphs showing the history of all injection and flow tests conducted on the slim holes. These should include plots of flow rates, surface and downhole pressures, and fluid temperatures versus time.

- Compilations of reservoir parameters interpreted from well test results, including injectivity and productivity indices, reservoir flow capacity values, skin factors, and any related parameters.

- Compilations of analytical results obtained from fluid samples collected during flow testing or by downhole sampling. These may be in a variety of graphical and tabular forms.

In addition to this information, the auxiliary data sources described in section 1 (table 1.1, column 2), should be available, including concise presentations of the results of all surface and shallow exploration work.

5.2 Estimation of Primary Resource Parameters

Primary resource parameters are estimated from the basic data categories shown in table 1.1. As discussed in section 2, for the purposes of probabilistic assessment of energy reserves, it is necessary to estimate the probability distributions or fixed values of certain key parameters. These include:

- Reservoir area

- Reservoir thickness

- Average reservoir temperature
- Rock matrix density
- Rock porosity
- Rock specific heat

In addition, other primary parameters that are used in a variety of assessment methods are estimated in this stage. For some purposes, it may be useful to estimate probability distributions for some of these parameters or subsets of these parameters. This can be done using the same techniques, following the guidelines discussed below. The additional parameters include:

- Reservoir depth
- Reservoir pressure
- Fluid chemistry
- Reservoir flow capacity

Guidelines for the estimation of each primary resource parameter are presented below. In each case, a definition of the parameter is presented, along with the data requirements for its estimation. Then, guidelines for selecting an appropriate function to model the probability distribution are presented. For many parameters, the guidelines are expressed in terms of selecting a minimum, maximum and most likely value of the parameter for use in developing a triangular probability distribution. The same quantities can also be used as the basis for selecting normal or lognormal functions to represent the distributions, by fitting these functions to the shape implied by the limits chosen.

In practice, estimation of the parameters and their probability distributions must be tailored to the specific conditions imposed by availability and quantity of data (including data from auxiliary sources), and by the nature of the reservoir itself. Ideally, probability distributions should be estimated in a manner that is as objective and standardized as possible, while taking maximum advantage of the information available.

PARAMETER: Reservoir Area

DEFINITION: The area underlain by reserves of geothermal heat, at commercial temperatures, that can be recovered by producing fluid from production wells (not necessarily equivalent to the area within which successful production wells can be drilled)

DATA REQUIREMENTS: Subsurface temperatures, based on static and flowing downhole temperature profiles. Also well productivities based on injection or flow test results, and the conceptual model of subsurface geology.

TYPE OF PROBABILITY DISTRIBUTION: Expected to be approximately normal, unless the reservoir is so small that there is some probability that no commercial resource is present. In practice the distribution can be approximated as triangular, provided that drilling results are sufficient to prove at least a minimal area. The probability distribution will be broad if holes are widely spaced or insufficient to define boundaries, narrow if coverage is more complete.

ESTIMATION: If holes are drilled densely enough to show a continuous area of commercially adequate temperatures within part or all of the area of investigation, then it is usually possible to define a minimum area based on those holes. This is done by drawing a boundary around the "hot" holes (those intercepting temperatures above the selected cutoff), with the boundary defined either by "cold" holes, or by an arbitrary limit of influence if there are no cold holes beyond the hot area.

If one or more "hot" holes are too isolated for contouring, each contributes to the minimum area a circle of chosen radius based on the estimated minimum area of influence (this must be chosen on the basis of various field characteristics).

Most likely and maximum areas should reflect reasonable and optimistic extrapolations, respectively, of the reservoir area, based on drilling coverage and the contoured distribution of temperature. These extrapolations depend largely on the deduced trend of temperature increase with depth (i.e. increasing steadily, becoming isothermal, or reversing) near the boundaries of the minimum area.

Although this estimation of the reservoir area does not require that commercial levels of permeability exist throughout the reservoir volume, it is necessary that permeable zones be sufficiently distributed to allow recovery of heat throughout the reservoir by commercially drillable wells. Therefore, areas of widespread low permeability (i.e. areas of dry holes only) must be excluded from the reservoir area. Such areas usually must be identified based on the overall conceptual model of the system, and the uncertainty in their estimation should be incorporated into the reservoir area probability distribution.

NOTES: Adjustments to the distribution model may be made on the basis of other information that emerges from conceptual modeling. For instance, subsurface and surface geologic modeling may indicate strong continuity of productive horizons, or the existence of structures that bound the reservoir. However, careful judgement should be used in applying such features, especially if their presence or location is speculative.

PARAMETER: Reservoir Thickness

DEFINITION: The vertical thickness of the reservoir from which heat may be extracted above the designated cutoff temperature. It is not limited to the interval that may be reached by deep wells, as such wells may be capable of extracting heat from deeper than their bottomhole depths.

DATA REQUIREMENTS: The most important source of data is from static and flowing downhole temperature surveys run in stabilized holes. These may be used to identify the thickness penetrated in each well that is above the chosen resource cutoff temperature. Also, the overall conceptual hydrogeological model of the reservoir is important in determining the subsurface geological structure and patterns of fluid movement that ultimately control the temperature distribution, thereby allowing better extrapolation of temperatures to undrilled depths. As such, a variety of other drillhole information, as well as auxiliary data such as surface exploration results, may be used via the conceptual model.

TYPE OF PROBABILITY DISTRIBUTION: Expected to be normal if slim holes penetrate a significant part of the reservoir; otherwise may be lognormal if the known minimum thickness is small and the potential maximum thickness is large. Either case can be adequately represented by a triangular distribution.

ESTIMATION: If possible from available downhole data, the subsurface distribution of temperature should be contoured to provide the most reliable model of (minimum) reservoir thickness. If contouring cannot be reliably carried out, then reservoir thicknesses penetrated by individual holes should be determined and compiled statistically.

Typically slim hole drilling penetrates only a portion of the reservoir. As a result, most likely and maximum values of reservoir thickness must be estimated by extrapolating temperatures to depths at or beyond the economic limit of drilling. This extrapolation is based on the three-dimensional model of temperature developed by contouring and by the overall conceptual model of the system. As with reservoir area, the estimation of most likely and maximum thicknesses will depend on data density and on the interpretation of temperature trends. Also it must be judged whether permeability is sufficiently distributed to provide some recoverability throughout the thickness estimated; this too is usually determined using the conceptual model of the system.

PARAMETER: Reservoir Depth

DEFINITION: The depth from the ground surface to the top of the reservoir zone (i.e. the top surface of the interval of temperature higher than the selected cutoff temperature, where heat is recoverable). If more appropriate to the particular assessment, the reservoir depth may be expressed as elevation, or the drilled depth of directional wells required to reach the reservoir.

DATA REQUIREMENTS: Plots of static temperature surveys versus depth are the primary tool for locating the top of the reservoir. Also of use may be temperature surveys run under flowing conditions, bottomhole and fluid temperatures measured during drilling, and alteration and lithology information.

TYPE OF PROBABILITY DISTRIBUTION: Generally can be modeled as a normal distribution if the reservoir top is reasonably constrained by adequately spaced drillholes, and a triangular distribution is usually an adequate approximation. Lognormal or even rectangular distributions may be more appropriate if the reservoir top is poorly constrained, especially if there is evidence that the surface is irregular or strongly dipping.

ESTIMATION: The physical distribution of the reservoir depth is best estimated by contouring, if the data are sufficient. For the probability distribution, the most likely value can be calculated by determining the mean depth indicated by contouring, unless there is strong evidence, such as a regular dipping surface, that another value should be used. If data are insufficient for contouring, the average reservoir intercept depth in available holes may be used.

Minimum and maximum values should be estimated on the basis of the confidence level of the estimated mean depth value. This must be guided by the apparent regularity of the reservoir top and the density of data. An asymmetrical distribution, with the maximum further from the most likely value than the minimum, may be appropriate if a large proportion of holes do not reach the reservoir, so that the minimum depth is better constrained than the maximum.

PARAMETER: Reservoir Temperature

DEFINITION: The distribution of temperature or, for purposes of reserves calculation, the average temperature of the reservoir volume. The reservoir volume includes all rock and fluid above a specified cutoff temperature, provided that some fraction of the heat contained is recoverable. Multiple cutoff temperatures may be applied to a given reservoir, resulting in different estimated average temperatures in separate calculations of reserves.

DATA REQUIREMENTS: Static downhole temperature surveys run in stabilized wells are the primary tool used to interpret equilibrium temperature profiles and thereby the distribution of temperature in the reservoir. Other information may be useful, including flowing temperature surveys, bottomhole drilling fluid temperatures, alteration and lithology information, and theoretical and statistical data.

TYPE OF PROBABILITY DISTRIBUTION: A normal distribution may be the best model for the probability distribution of average temperature, if data are adequate to reliably estimate temperature over much of the reservoir volume and the cutoff temperature is significantly lower than the average temperature. If lack of data or a relatively high cutoff temperature constrain the lower end of the distribution more than the upper, a lognormal distribution may be more appropriate. If data are extremely sparse, a rectangular distribution may be appropriate. A triangular function is normally sufficient to approximate a normal or lognormal model.

ESTIMATION: The physical distribution of temperature should be estimated by interpreting stable temperature profiles in as many wells as are available, and then contouring temperatures at a series of levels through the reservoir. This allows reliable estimation of temperature at single points or over specific volumes in the explored portion of the reservoir, and often permits extrapolation of temperatures to unexplored depths or areas with reasonable accuracy.

If many holes do not penetrate deeply into the reservoir, as is often the case, the average temperature over the explored volume can generally be taken as the minimum temperature. This assumes that temperatures are not reversing with depth; if they do then a lower minimum must be chosen.

If the temperature over most or all of the estimated reservoir volume is well known, then the average temperature over the explored volume may be used as the most likely temperature, and the minimum temperature will normally fall close to this value. Otherwise, the most likely temperature is best estimated by projecting reservoir temperatures to the maximum reservoir depth, assuming that temperature conditions become isothermal once the maximum observed temperatures or typical reservoir temperatures are reached.

The maximum average temperature may be estimated by making the most optimistic projection of reservoir temperatures to unexplored depths and areas; for example, by assuming that temperatures continue to increase linearly to the bottom of the reservoir interval.

PARAMETER: Reservoir Pressure

DEFINITION: The static pressure of the geothermal fluid (water, steam or water + steam, including noncondensible gases) within the reservoir volume.

DATA REQUIREMENTS: Bottomhole pressures or water level measurements made during drilling, and static downhole pressure surveys are the primary tools for interpreting reservoir pressure. Also of use may be records of circulation losses, pressure surveys during flow or injection, downhole temperature surveys, and spinner surveys.

ESTIMATION: Probability distributions of reservoir pressure are normally not needed for resource assessment, but the physical distribution of pressure and of pressure-related parameters are often used in several types of analysis. Most importantly, reservoir pressure is indicative of thermodynamic conditions such as the presence or absence of steam or two-phase zones in the reservoir, and of hydrologic conditions as indicated by pressure gradients within the reservoir. Therefore, pressure distribution is often investigated as part of the overall conceptual and numerical modeling effort during resource assessment.

Estimation of pressure distribution may be approached in several different ways depending on the needs of the particular assessment and on the data available. Different techniques include construction of level maps of static pressure measured in wellbores, profiling of bottomhole pressures measured during drilling, mapping of static water levels in drillholes, and mapping of zones of different phases (water, steam, or two-phase) in the reservoir.

PARAMETER: Rock Density

DEFINITION: The density of the rock matrix within the reservoir volume from which heat energy is expected to be extracted.

DATA REQUIREMENTS: Density measurements of cores representative of reservoir rock can define rock densities in drilled zones with high precision. In practice it is found that variations in reservoir rock densities do not strongly affect the estimation of reserves. Therefore, rock densities can normally be estimated satisfactorily from lithologic and alteration descriptions of drilling samples, using statistical knowledge of the densities of specific rock types. Indirect information such as drilling penetration rates and geophysical logs may sometimes be of use in such estimations.

TYPE OF PROBABILITY DISTRIBUTION: Because of the small impact of rock density variations on reserves calculations, it is usually sufficient to model density as a fixed value rather than as a probability distribution. If estimation of a probability distribution is desired, a normal distribution (or a triangular approximation) is most useful if adequate measurements or statistical data are available. Otherwise, a rectangular distribution may be appropriate if data are sparse.

ESTIMATION: When reliable density measurements are available, these can be used to calculate the average rock density as a fixed value, or, if necessary, the distribution of measured densities can be used as the estimated probability distribution. If no measurements are available, densities should be estimated by first determining from petrographic data the types and characteristics of the rocks present, and determining their corresponding densities from statistical compilations.

PARAMETER: Rock Porosity

DEFINITION: The fraction of open space, including any fracture space and intergranular pore space, within a given unit of volume in the reservoir.

DATA REQUIREMENTS: Because of the importance of fracturing in most geothermal reservoirs, it is usually difficult or impossible to estimate overall reservoir porosity directly from measurements of porosity, even if good core samples are available. Therefore, while such measurements may be used as part of the database for estimating reservoir porosity, other information such as the overall geological model of the system, statistical information from other fields, and perhaps theoretical data, is needed to characterize reservoir porosity.

TYPE OF PROBABILITY DISTRIBUTION: Often, insufficient data are available to constrain the probability distribution of porosity reasonably well, and a rectangular model is most appropriate. If available data are sufficient to characterize the physical distribution of porosity or estimate an average porosity, then a normal distribution may be used, approximated by a triangular function if desired.

ESTIMATION: If porosity measurements are available, they should be evaluated to determine to what degree they may be representative of reservoir porosity. Then limits on porosity may be chosen based on the measurements and on the other information noted above. Estimation of reserves is not strongly sensitive to variations in reservoir porosity; therefore a relatively standard range of porosity can usually be selected, without the need for numerous measurements or exhaustive investigation.

PARAMETER: Rock Heat Capacity or Specific Heat

DEFINITION: The heat capacity of the solid rock matrix within the reservoir volume. Heat capacity is defined as the quantity of heat necessary to raise the temperature of a unit of mass of material by one degree, and therefore has units such as cal/g/°C. Specific heat is a dimensionless quantity that is the ratio of the heat capacity of a substance to the heat capacity of water at 15°C. Either quantity can be used to determine the amount of heat energy stored in a volume of rock at a given temperature.

DATA REQUIREMENTS: Petrographic descriptions and classifications of the cuttings or core sample recovered during drilling are needed to determine the type and characteristics of the rocks present. Statistical and theoretical data are typically needed to determine the heat capacities of the rock types.

TYPE OF PROBABILITY DISTRIBUTION: In practice, if the reservoir rock is reasonably well known and not extremely heterogeneous, the average heat capacity of the reservoir rock can be estimated accurately enough to be represented by a single value rather than a probability distribution. Otherwise, a relatively narrow rectangular distribution is sufficient, unless there is strong evidence to select another distribution type.

ESTIMATION: Laboratory determinations of specific heat of rock samples normally are not justified due to the relatively small impact of possible variations in heat capacity on reserves estimates. Generally, it is sufficient to estimate the typical heat capacity for the rock types present from statistical compilations of rock properties, once the rock types have been properly identified and characterized by petrographic studies. An average heat capacity, or probability distribution of average heat capacity, can then be chosen on the basis of the relative abundances of the rock types in the reservoir.

PARAMETER: Reservoir Fluid Chemistry

DEFINITION: Fluid chemistry encompasses a wide variety of chemical properties of the reservoir fluid that may have an impact on reservoir and well performance, or on the modeling of the reservoir. Examples of such properties are concentrations of ionic species in the reservoir fluid (and produced fluids), concentration of dissolved noncondensible gases, overall fluid salinity, and isotopic composition of the reservoir water, among others.

The chemical properties of interest will depend on the particular field being investigated, but among the most important will include those that may affect the potential for scaling of wells or surface equipment (e.g. SiO2, carbonate species), the need for environmental mitigation (e.g. H2S, total dissolved solids or certain metals), and power plant performance (especially noncondensible gases).

Estimation of these parameters from slim hole data should be carried out on a case-by-case basis; an estimation of probability distribution may be useful for any that have a direct and critical bearing on field development and management.

DATA REQUIREMENTS: Chemical analyses from fluid samples collected during flow testing or downhole sampling. Ideally these will include samples of separated steam and brine collected from flowing wells after a sufficient flow period to ensure production of uncontaminated reservoir fluid. Downhole samples and samples of flashed brine or of brine contaminated by drilling fluid are of lesser reliability but may still be useful. If no fluid samples are available, very approximate estimates of fluid chemistry parameters can sometimes be made from petrological and fluid inclusion studies; however these are of low reliability because of their indirectness, and their use will result in highly uncertain estimates.

TYPE OF PROBABILITY DISTRIBUTION: Variable, depending on the availability of data and the quantity estimated. Lognormal to normal distributions may be appropriate for most parameters in many or most systems where fluid chemistry is expected to be relatively constant or vary systematically. In a number of systems, two or more distinctly different fluid types may be present, leading to bimodal or otherwise complex distributions. In such cases it may be difficult or impossible to reliably determine probability distributions from sparse data.

ESTIMATION: Best carried out by an experienced geochemist with insight into the specific behavior and occurrence of the chemical species concerned. If chemical data are abundant and from adequately distributed slim holes, it may be possible to characterize physical and probability distributions quite precisely, approximating the actual distribution in the reservoir. If data are sparse, the ability to estimate the distribution will depend heavily on evidence for reservoir homogeneity or heterogeneity.

PARAMETER: Reservoir Flow Capacity

DEFINITION: The characteristic kh or permeability-thickness product of the reservoir volume within which production wells can be feasibly drilled for the recovery of geothermal reserves.

DATA REQUIREMENTS: Injection or flow test results, especially details of injection/flow rates and pressure transient data (pressure buildup or falloff). Also interference data if available. May be supplemented by conceptual geologic modeling of the reservoir.

TYPE OF PROBABILITY DISTRIBUTION: Estimation of the probability distribution of reservoir flow capacity is not commonly required. The distribution may be approximately normal in reservoirs of average to high flow capacity, if available data are substantial. It may be lognormal in low-permeability reservoirs or if database is small. In either case it could be approximated well by a triangular distribution.

ESTIMATION: Calculated flow capacities from production, injection and interference tests are examined to determine characteristic reservoir flow capacity, and to identify significant heterogeneities in the distribution of reservoir permeability. This information is often used in the process of estimating the energy recovery factor, used in calculating recoverable reserves. Also, estimated flow capacity is an essential input to wellbore modeling studies used to forecast characteristics of large-diameter wells. Although flow capacities calculated from well test results serve to characterize overall reservoir permeability, integrated numerical modeling is necessary for the estimation of rock permeability in 3-dimensional detail.

5.3 Estimation of Secondary Resource Parameters

This section discusses several secondary resource parameters that can be readily determined once the primary parameters have been investigated and estimated. Section 5.4 discusses reservoir performance parameters, particularly well performance characteristics, that must be estimated using the aid of wellbore simulation methods or other special techniques.

Reservoir volume and fluid content

These parameters can be derived directly from the values or probability distributions of reservoir area, thickness and porosity. Combining area and thickness by multiplication yields the overall reservoir volume, and combining volume with porosity by multiplication gives the fluid volume in the reservoir, assuming that the entire reservoir volume is saturated, as is normally the case.

The total mass of fluid in the reservoir can normally be estimated easily from the fluid volume if the reservoir is entirely or predominantly single-phase water. For reservoirs that contain significant two-phase or steam zones, estimating total fluid mass may require complex and highly approximate calculations.

Reservoir fluid density and fluid enthalpy

These parameters may be determined from the deduced values or distributions of reservoir temperature, fluid chemistry and pressure. Fluid density for low-salinity water is a direct function of the water temperature. As salinity increases, the fluid chemistry may need to be taken into account to correct for the presence of dissolved solids. These calculations are straightforward.

If two-phase or steam zones are present, the fluid density at various saturation conditions can be calculated relatively easily, but the distribution of these conditions will likely be very difficult to determine. Numerical modeling may be necessary to adequately model the physical distribution of fluid density.

Calculation of fluid enthalpy is analogous to that of fluid density. Enthalpy in a low-salinity single-phase water reservoir can be estimated accurately from deduced temperature using steam tables. Corrections can be made as needed for salinity and gas content. In a two-phase reservoir, overall fluid enthalpy can rarely be estimated precisely because ratios of steam to water over various reservoir volumes are extremely difficult to estimate without detailed numerical modeling.

Reservoir volumetric specific heat and heat content

The volumetric specific heat of any part of the reservoir or the entire reservoir volume is given by:

$$C_v = \rho_r C_r (1-d) + \rho_f C_f d \qquad (2.7)$$

The component parameters of C_v, as described in Section 2.5, are rock matrix and fluid densities, rock matrix and fluid heat capacities, and reservoir porosity. This quantity forms a central part of the estimation of recoverable energy reserves. Again, two-phase or steam conditions in the reservoir will make this equation more complex.

The heat content of a particular reservoir volume or the entire reservoir can be calculated by combining the expression for volumetric heat capacity with reservoir temperature. Temperature in this case must be with respect to a specified reference temperature.

Permeability distribution

Quantitative estimation of rock permeability over any reservoir volume is complex, and normally can be adequately modeled only by the use of numerical simulation methods. However, much qualitative information on the location and relative magnitude of permeability can be obtained from primary resource parameters. This information is useful in further assessment of the resource, particularly in estimation of resource recovery factors, and field development considerations such as the siting of production and injection wells.

Temperature and pressure distribution in the reservoir is used as a guide to determine patterns of fluid movement, and thereby to identify zones of relatively high permeability, impermeable boundaries, and other such features. This information is integrated with a geological model to form the conceptual hydrogeological model of the geothermal system. The kinematics of flow in such a model are constrained by the permeability distribution.

Estimates of apparent rock permeabilities over at least limited reservoir volumes can be implied from reservoir flow capacities calculated from injection test, production test or interference test results. These can yield at least order-of-magnitude estimates of characteristic reservoir permeability. Well test results can also provide information about such features as hydraulic boundaries to the system and the presence or absence of natural recharge. Along with information about the type or style of permeability present in the reservoir, these estimates are critical in assessing the resource recovery factor for a reservoir.

Energy recovery factor

This factor is an expression of the fraction of heat-in-place that can be commercially recovered using available technology or under a specific scheme of development. It is an important parameter in the reserves estimation algorithm (see equation 2.6), and it is the most difficult parameter to estimate, as it depends upon: (a) the production/injection scheme to be employed; (b) the distribution, heterogeneity and anisotropy of rock and fluid properties in the reservoir; (c) reservoir drive and heat-transfer mechanisms; and (d) the extent of heat and fluid recharge from outside the reservoir. The first item is known from the operator's development plans; in the early development stage such plans are not available. The second item is a combination of primary resource parameters that is difficult to quantify. The critical parameters in this regard are the distributions of temperature, steam saturation and permeability.

The U. S. Geological Survey (White and Williams, 1975; and Muffler and Guffanti, 1978) assumed that 50% of a geothermal reservoir typically is porous and permeable, and ideally, 50% of the heat content (above 15°C) in the porous and permeable parts of a reservoir is recoverable, giving an overall recovery factor (r) = 0.25. Evidence from operating fields so far has not contradicted that this assumption is reasonable. Therefore, r is numerically about half of the porous and permeable fraction of the bulk volume of a reservoir. For specific prospects, a value of r can be estimated based on (a) the conceptual model of the geothermal system with or without quantitative reservoir modeling, and (b) experience from production histories of similar systems around the world.

5.4 Estimation of Well and Reservoir Performance Parameters

A number of parameters related to the performance of individual wells drilled in the reservoir may be estimated from primary resource parameters without fieldwide integrated modeling. Some of these are indicated fairly directly by simple examination or analysis of other parameters. For instance, drilling targets and therefore total well depths, casing depths, and well designs may be chosen by reviewing temperature distribution, permeability distribution, and if necessary the overall hydrogeological model of the system.

For planning of drilling requirements in terms of the number and spacing of production and injection wells, it is necessary to estimate reliably the expected productivity of wells by forecasting flow rates, wellhead pressures, and production enthalpies. The initial values of these parameters can be estimated by wellbore simulation methods, using the well designs determined as discussed above, and using parameters such as reservoir flow capacity determined from slim hole injection testing, production testing and interference testing results.

5.5 Estimation of Recoverable Energy Reserves

Section 2.5 discussed the mathematical basis for the probabilistic method of estimating recoverable energy reserves using the probability distributions of specific primary and secondary resource parameters. The Monte Carlo technique combines the probability distributions according to the algorithm presented, to yield the estimated distribution of the quantity of energy that may be extracted from the reservoir, assuming that exploitation by drilling production wells is physically and economically feasible.

The calculation of reserves allows for the first steps in planning possible development scenarios to be carried out. By determining the reserves present at the desired level of confidence, the expected lifetime of the field may be determined if a plant capacity is chosen, and vice versa. Computer programs developed to carry out the Monte Carlo calculations commonly allow such scenarios to be examined automatically, using supplied assumptions about field lifetime, plant factor and other operating parameters to generate an estimated probability distribution of field capacity expressed in megawatts. By integrating the distribution curve, or numerically summing such a curve calculated in histogram form, one can obtain an overall indication of the value of a prospect, the value being objectively weighted for the estimation uncertainties of its components.

The reserves estimation is carried out by a computer program that accepts as input the probability distributions of component parameters. These may be specified either by analytical functions, or, if desired, by numerical representations of probability in each of a chosen number of discrete intervals. A simple and practical method is to represent all uncertain parameters as either triangular or rectangular distributions. In this way, probability distributions can be estimated rapidly and specified with a minimum number of parameters (2 or 3 per distribution). Other inputs are fixed quantities, such as resource parameters that can be estimated precisely, calculated thermodynamic parameters, cutoff temperature, and selected operating parameters.

It has been found through experience that 5 resource parameters have a sufficiently large impact on energy reserves to be input as probability distributions, as opposed to fixed quantities. These are:

- Reservoir area
- Reservoir thickness
- Average reservoir temperature
- Rock porosity
- Energy recovery factor

The computer algorithm follows the process described in section 2.5, combining the input distributions using the Monte Carlo technique to generate the joint probability distribution of recoverable energy reserves. The reserves distribution can be expressed as a discretized set of frequencies within specified outcome intervals, either as a frequency histogram or as a cumulative probability histogram, or both. In addition, the discretized distributions of megawatt capacity (given a specified field lifetime), energy reserves per unit area, or other desired parameters may be computed as part of the reserves program.

The discretized probability distributions are flexible tools for displaying and using the results of the Monte Carlo estimation technique. Standard plots of frequency and cumulative probability histograms of reserves and other parameters can be generated directly, using commonly available graphics software. The graphics may be used as part of later economic analysis, or the distributions themselves may be used in computerized form as inputs to economic analysis software.

5.6 Reservoir Performance Forecasting

For the majority of prospects, the calculation of primary and secondary resource parameters, and the estimation of energy reserves, is sufficient to provide the basis for an economic assessment leading to a decision to continue with development or abandon the project. Slim hole drilling programs can therefore normally be planned to fulfill the data requirements of the estimation steps described so far.

Detailed forecasting of reservoir behavior over the lifetime of a proposed project requires modeling using specialized techniques of numerical reservoir simulation, which are beyond the scope of this volume. Examples of parameters that might be investigated using simulation techniques are (table 1.1, column 6):

- Reservoir temperature and pressure changes over time
- Decline rates of production wells
- Drilling requirements over time for production and injection wells
- Injection management strategy

Adequate numerical simulation of a geothermal reservoir requires a diverse and sound data base, including:

- A well-defined conceptual hydrogeological model of the geothermal system

- Adequate characterization of the stable temperature and pressure distribution in the reservoir

- Substantial well test data from injection, production and interference tests of reasonably long duration

Most slim hole drilling programs are not likely to generate a sufficient data base to justify a comprehensive numerical modeling effort. However, data collection, testing and monitoring during and after drilling can be carried out with eventual modeling in mind. In this way, an evolving numerical model of the field can be developed as field development and startup take place.

6. EXAMPLE AND DISCUSSION OF APPLICATION

The application of the slim hole methodology may be understood by following a simple and brief example from the exploration phase to the calculation of recoverable energy reserves. Figure 6.1 shows a map of a hypothetical geothermal prospect in which the potential developer holds the lease position shown. At this stage the surface exploration work has been completed, including the drilling of a number of shallow temperature gradient holes of depths up to several hundred feet deep. There are no physical or regulatory constraints on the siting and drilling of deeper holes, with the exception that the terrain in the northern portion of the lease area is too rugged for deep drilling.

Review of available geological, geophysical and geochemical data for this hypothetical area has indicated that the temperature gradients measured in the shallow holes probably provide the best guide to where high temperatures may be located at depth. In this case, a cutoff temperature of 350°F has been chosen as the economic lower limit of useful temperature based on the developer's needs. It is hoped that fluids at or above this temperature will be encountered beginning at depths of 4,000 feet or less. This means that the most promising areas for deep drilling are those where the shallow temperature gradient exceeds 8°F per 100 feet of depth. The limit of this temperature gradient as defined by the shallow holes is shown in figure 6.1. The area within this limit is selected as the primary area for exploration by slim hole drilling, recognizing that, if conditions are favorable, there may be additional areas that have commercial potential.

Based on these criteria and on consideration of data requirements and available budget, 9 sites for slim holes are selected and permitted. These sites are shown in figure 6.1. The sites have been chosen to provide systematic coverage with the area defined by the favorable temperature anomaly and limited by terrain. The holes are programmed to be drilled to a uniform chosen depth (perhaps about 6,000 feet), but with the flexibility to change the termination depth based on indications of temperature and permeability conditions obtained during drilling or from previously drilled holes. Thus when the holes are drilled, their depths vary according to the judgement of the specialists collecting and analyzing data as the drilling proceeds.

Figure 6.2 shows the results of the hypothetical drilling program in map and cross section form. Although much detailed information is obtained from each hole, all contributing to the evolving conceptual model of the field, for simplicity the results of holes are classified according to whether each hole is "hot" (reaching temperatures above the 350°F cutoff) or "cold" (below cutoff), and permeable (with significant circulation losses or fluid entries) or dry (no losses or entries). The four possible combinations of these results are shown in figure 6.2.

Also shown in figure 6.2 is the distribution of temperature at the maximum depth explored by the slim holes (around 5,000 feet below the average ground surface). Most of the area of the leasehold is found to be at or above the reservoir cutoff temperature at this depth, indicating that some level of recoverable energy reserves is present. Although the terrain has prevented drilling in the northern part of the leasehold, temperatures can be extrapolated into this area giving reasonable confidence that all or part of the northern area exceeds the cutoff temperature, but the exact temperatures are uncertain. Similarly, the slim holes permit some extrapolation of temperature to greater depths, although the temperatures at the maximum depth of commercial extraction cannot be known precisely.

A first indication of the degree to which energy reserves may be extractable from the leasehold is given by the distribution of permeable wells (map, figure 6.2) and the location of circulation loss zones within those wells (shown in the cross section in figure 6.2). A significant area within the reservoir appears to have some degree of permeability that may allow commercial fluid extraction. Correlation of circulation loss locations with the downhole lithological summaries prepared from the slim holes has indicated that most or all loss zones occur within a single distinguishable formation of fractured volcanic rock, that is horizontal to gently dipping within the leasehold area. The distribution of loss zones within this rock unit suggests that most or all of the unit may be expected to be permeable, and that little to no permeability is likely to be present in the overlying rocks. However, the information gained from the slim holes is insufficient to determine whether rocks below the productive formation will be largely permeable or impermeable.

This simple model of the geothermal system can be used to illustrate the process of estimating the probability distributions of resource parameters. In practice, much more detailed analysis and presentation of a greater variety of drilling, logging and test data from the slim holes would be carried out before proceeding to the resource assessment stage. The probability distributions of the five resource parameters used as uncertain inputs to the Monte Carlo reserves estimation method (reservoir area and thickness, average reservoir temperature, rock porosity, and recovery factor) are estimated as follows.

A minimum estimate of reservoir area (see definition in section 5) can be chosen by drawing a narrow "information boundary" around the holes that reached temperatures above the 350°F cutoff. This represents the most conservative estimate possible, because it ignores any extrapolations of high temperatures to other areas or to greater depths. The outline of the minimum area is shown in figure 6.3.

The most likely reservoir area can be chosen on the basis of the estimated 350°F contour shown in figure 6.2. This includes all of the area in the northern part of the leasehold, and some extension to the south. To estimate the maximum reservoir area, it can be assumed that deeper drilling in the southern part of the leasehold has a reasonable chance to encounter commercial temperatures, based on the known temperature distribution. Therefore the maximum reservoir area within the leasehold is simply the leasehold area itself.

The minimum, most likely and maximum reservoir areas estimated in this way can be used as the parameters of a triangular probability function, shown in figure 6.4. Because the most likely area is closer to the maximum than the minimum area, the function has a slight asymmetry.

As discussed in section 5, the reservoir area defined in this way does not imply that a commercial production well can be drilled at any given point within the area, but simply that some part of the energy contained in each part of the reservoir area can be extracted commercially. In this case it is judged that all parts of the leasehold are sufficiently close to permeable slim holes (figure 6.2) to assume that inadequate permeability will not completely prevent heat extraction at any point.

Reservoir thickness is estimated by examining the vertical intervals of high temperature penetrated by the slim holes. In practice this should be done for each hole, covering the entire area, but the cross section in figure 6.2 serves as an example of the process. Because the 350°F surface dips significantly, it is necessary to estimate the average interval that is "proved" to be above the cutoff temperature based on the available drilling results; this interval can be taken as the minimum reservoir thickness. Examination of the cross section in figure 6.3 suggests that the interval shown is a reasonable estimate of this thickness.

Because temperatures are found to increase continuously with depth in the hypothetical prospect, a most likely reservoir thickness equal to twice the minimum thickness can safely be estimated. The maximum thickness is not much greater than this, because it has been decided that production wells for this field will not be drilled to more than about 8,000 feet unless absolutely necessary; therefore the maximum depth of the bottom of the reservoir is assumed to be about 10,000 feet. The resulting triangular distribution of reservoir thickness is shown in figure 6.4.

The probability distribution of average reservoir temperature is guided by the estimated physical distribution of temperature in the subsurface, as modeled from temperatures measured in the slim holes. Again, a complete three-dimensional model of temperature is normally used in this process, but the level map shown in figure 6.2 serves as an example. Within the area that is well-explored by slim hole drilling and estimated to be above the 350°F cutoff, the average temperature is slightly more than 360°F. A minimum average reservoir temperature of 362°F is therefore an acceptable estimate. If the less-explored area to the north is taken into account, its higher extrapolated temperatures lead to an estimated average of about 370°F, which can be taken to be the most likely value of average temperature. A still higher average of perhaps 375°F might be estimated if it is assumed that higher temperatures will be encountered at depths below the limit of information available from the slim holes. Thus a triangular probability distribution with minimum, most likely and maximum values of 362°F, 370°F and 375°F is appropriate for the reservoir within the leasehold area.

The potential developer of the hypothetical prospect chose not to perform detailed petrophysical studies of rock samples obtained from the slim holes, for reasons of cost. Statistical information on porosities of the rock types encountered in the reservoir is therefore used to estimate the upper and lower limits of a rectangular probability distribution for reservoir porosity, shown in figure 6.4.

Using the guidelines discussed in section 5 for estimating the energy recovery factor, its probability distribution can be selected using the information shown in figure 6.2. A quick examination of the map suggests that a minimum of perhaps 70% of the reservoir area is likely to be permeable, and the cross section similarly suggests that 30% or more of the reservoir thickness will be permeable. Combining these with the assumption that 50% of the heat from the permeable volume can be recovered means that the minimum recovery factor for the reservoir is 0.7 x 0.3 x 0.5 = 0.105. The most optimistic scenario is that the entire reservoir area and 60% of the thickness will be found to be permeable, so that the maximum recovery factor will be 1.0 x 0.6 x 0.5 = 0.3.

A most likely factor of 0.2 has been chosen based on the available information, but, as this example illustrates, estimation of the recovery factor is the most difficult and normally the most subjective of all the estimations that must be made in the reserves calculation process. A maximum of care should be taken to evaluate carefully all factors that might influence the choice of limits for the distribution. Figure 6.4 shows the triangular distribution selected for this case, but a rectangular distribution could be argued to be equally valid. In many cases, sensitivity studies carried out using different recovery factor distributions in the reserves calculations may be useful in assessing the impact of variations in assumed recovery factors.

With the estimation of uncertain parameters complete, the remaining step before calculation of recoverable reserves is the estimation or selection of fixed parameters needed for the Monte Carlo estimation process. As discussed in section 2, these include the density and heat capacity of the rock matrix and the reservoir fluid, the rejection (average ambient) temperature, and the plant factor and lifetime of the planned development. Normally the selection of these parameters does not pose any significant difficulties.

The Monte Carlo method for reserves estimation is applied to the parameters estimated above, either once, or several times if it is desired to examine, for example, different plant lifetimes, plant factors, or probability distributions of sensitive parameters. Results of the reserve estimation can then be presented graphically to show the distribution of total recoverable energy, energy per unit area, field capacity in megawatts over a the specified lifetime, or related parameters as desired.

Field capacity in megawatts is commonly of greatest interest for assessing the economic feasibility of a development project. Figure 6.5 shows a histogram of a typical probability distribution curve of field capacity. Figure 6.6 shows the cumulative probability curve for the same distribution. Such graphical representations of the reserves probability distribution make it a simple process to assess the degree of confidence with which it may be assumed that any particular level of reserves exists.

Monte Carlo simulation has many features which make it a realistic method of assessing reserves under uncertainty, and is often more realistic than either a deterministic or a parametric approach. However, it must be considered as a supplement to professional judgement and not a replacement for it. It is merely a convenient and rigorous method of combining professional expressions of judgment; the better the judgment, the better are the results. It cannot make those judgments, and the method is not intended as a replacement for good, sound thinking on the part of the geologist, geophysicist, geochemist or engineer.

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TABLES

Table 1.1. Chart of Resource and Reservoir Performance Parameters: Determination from Slim Hole Data

1. Slim Hole Data Categories	2. Auxiliary Data Categories	3. Primary Resource Parameters	4. Secondary Resource Parameters	5. Integrated Modeling Techniques	6. Tertiary Resource and Performance Parameters
A Lithology	*X* Surface exploration data	*1* Reservoir area *(H,G,K,X)*	*a* Reservoir volume *(1,2)*		*I* Recoverable energy reserves *(r)*
B Alteration		*2* Reservoir thickness *(H,L,A,B,Z)*	*b* Reservoir fluid content *(1,2,8,4,5)*		*II* Field capacity *(r,s)*
C Penetration rate					
D Drilling fluid temperatures	*Y* Statistical data from other fields	*3* Reservoir depth *(H,L,E,D,B,A)*	*c* Reservoir volumetric specific heat *(7,8,9,f)*	*(r) Probabilistic Estimation of Energy Reserves (1,2,4,7,8,9,f)*	*III* Field lifetime *(r,s)*
E Bottomhole temperatures		*4* Reservoir temperature *(H,L,D,E)*	*d* Reservoir heat content *(a,c)*		*IV* Well decline rate *(K,s)*
F Bottomhole pressures	*Z* Theoretical data		*e* Reservoir fluid enthalpy *(4,5,6)*		*V* Infill drilling requirements *(h,j,s)*
G Circulation losses		*5* Pressure distribution *(H,F,L)*	*f* Reservoir fluid density *(4,5,6)*		
H Static downhole temperature profiles		*6* Fluid chemistry *(Q,R)*	*g* Reservoir permeability distribution *(10,4,5,6)*		*VI* Reservoir pressure changes *(s)*
I Static downhole pressure profiles	*Data reduction and analysis procedures*	*7* Rock density *(A,B,C,J,Y,X)*		*(s) Reservoir Simulation Modeling (4,5,6,7,8,9, K,N,O)*	*VII* Reservoir temperature changes *(s)*
J Geophysical and other logs		*8* Rock porosity *(A,B,C,J,Y)*	**Secondary Reservoir Performance Parameters**		*VIII* Injection management strategy *(s)*
K Injection or production test flow rates		*9* Rock specific heat *(A,B,Y,Z,X)*	*h* Initial well flow rate *(10,4,5,w)*		*IX* Total life cycle energy *(r,s)*
L Inj/prod test P/T profiles		*10* Reservoir flow capacity *(N,O,Y)*	*i* Initial wellhead temperature *(10,4,5,w)*		
M Inj/prod test P/T spinner data			*j* Initial wellhead enthalpy *(10,4,5,w)*		
N Inj/prod test P/T pressure transients			*k* Well depth *(3,2,1,4)*		
O Inj/prod test P/T interference data		*(w) Wellbore Simulation (K,N,O,L,H,I,M)*	*l* Initial production well requirement *(h,j)*		
P Inj/prod test P/T tracer data			*m* Initial well spacing *(1,10,l,w)*		
Q Production test fluid samples			*n* Energy recovery factor *(8,9,10,4)*		
R Downhole fluid samples			*o* Initial injection well requirement *(O,P,10,4,5)*		

FIGURES

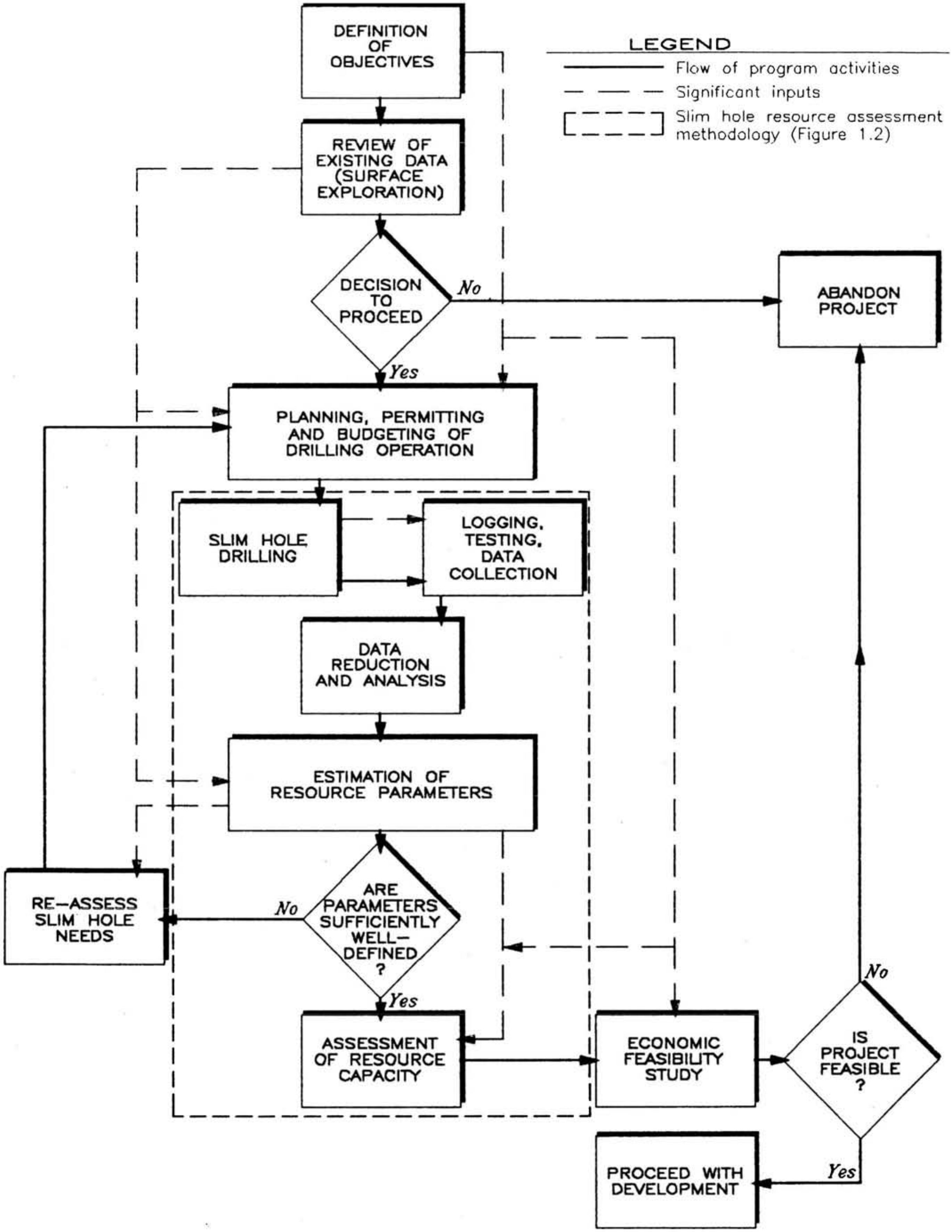

Figure 1.1: Flowchart of resource assessment program

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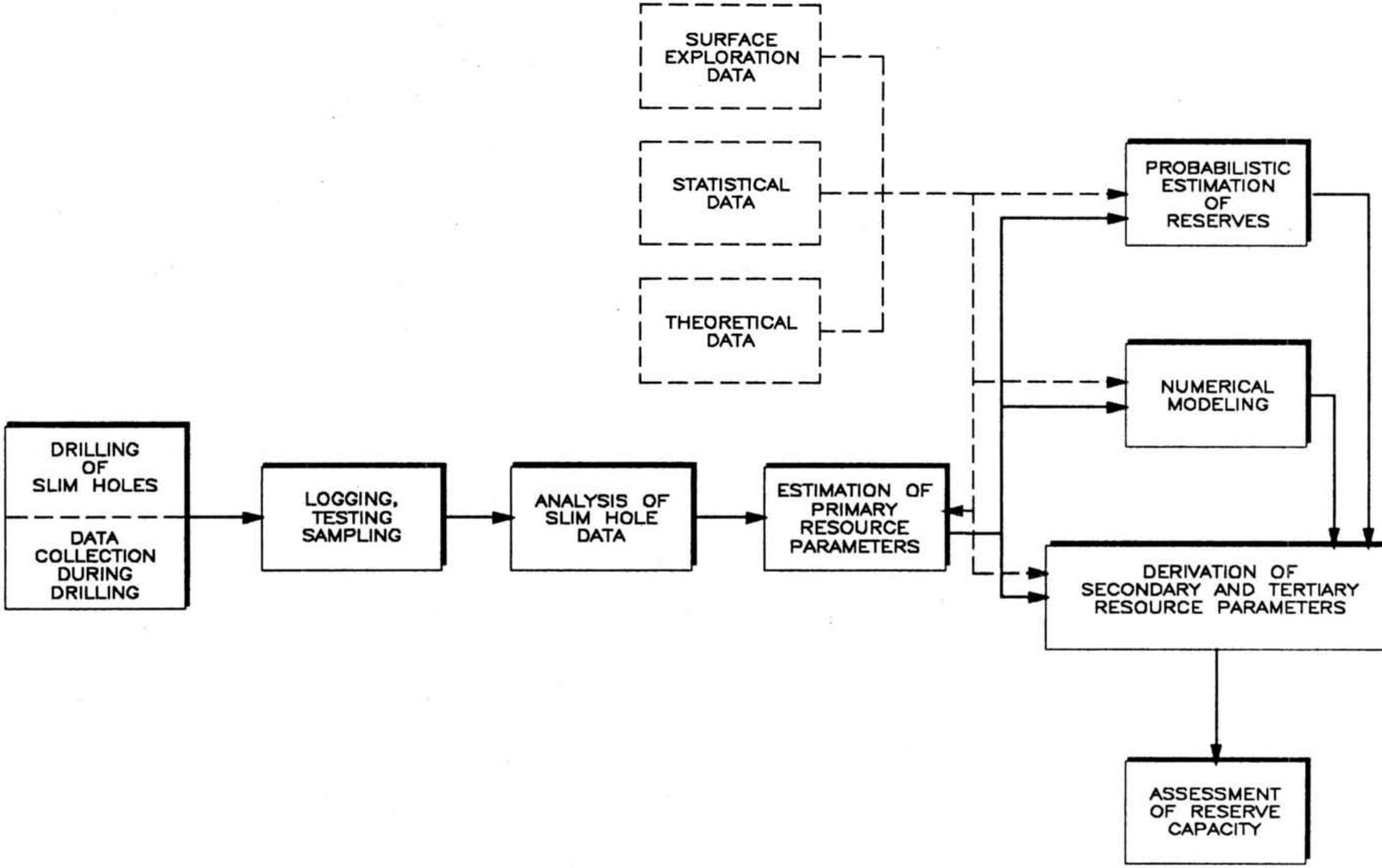

Figure 1.2: Flowchart of methodology for reservoir assessment using slim hole data

Figure 2.1. Example of Rectangular Probability Distribution of Average Reservoir Temperature

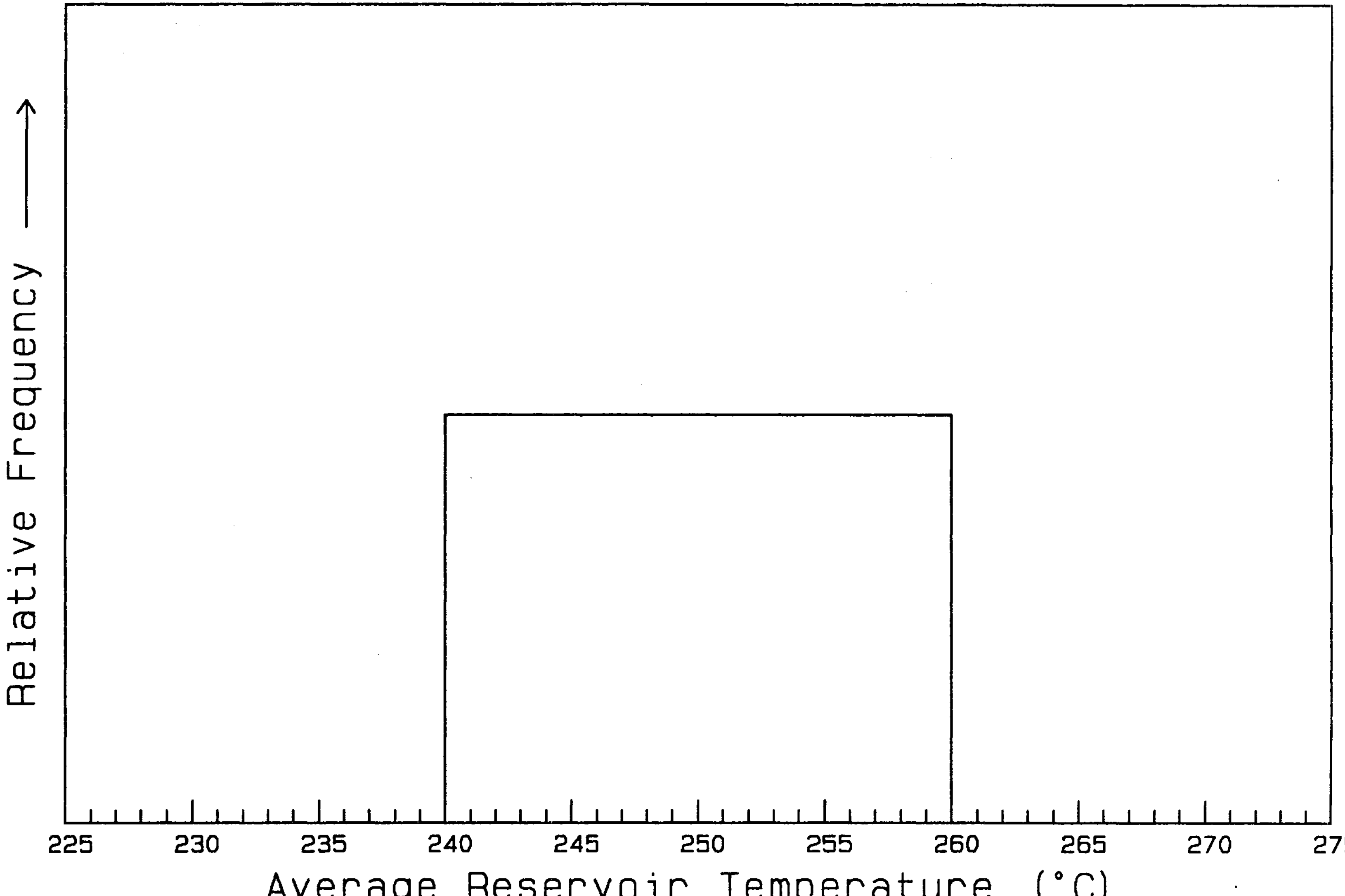

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Figure 2.2. The Normal (Gaussian) Distribution)

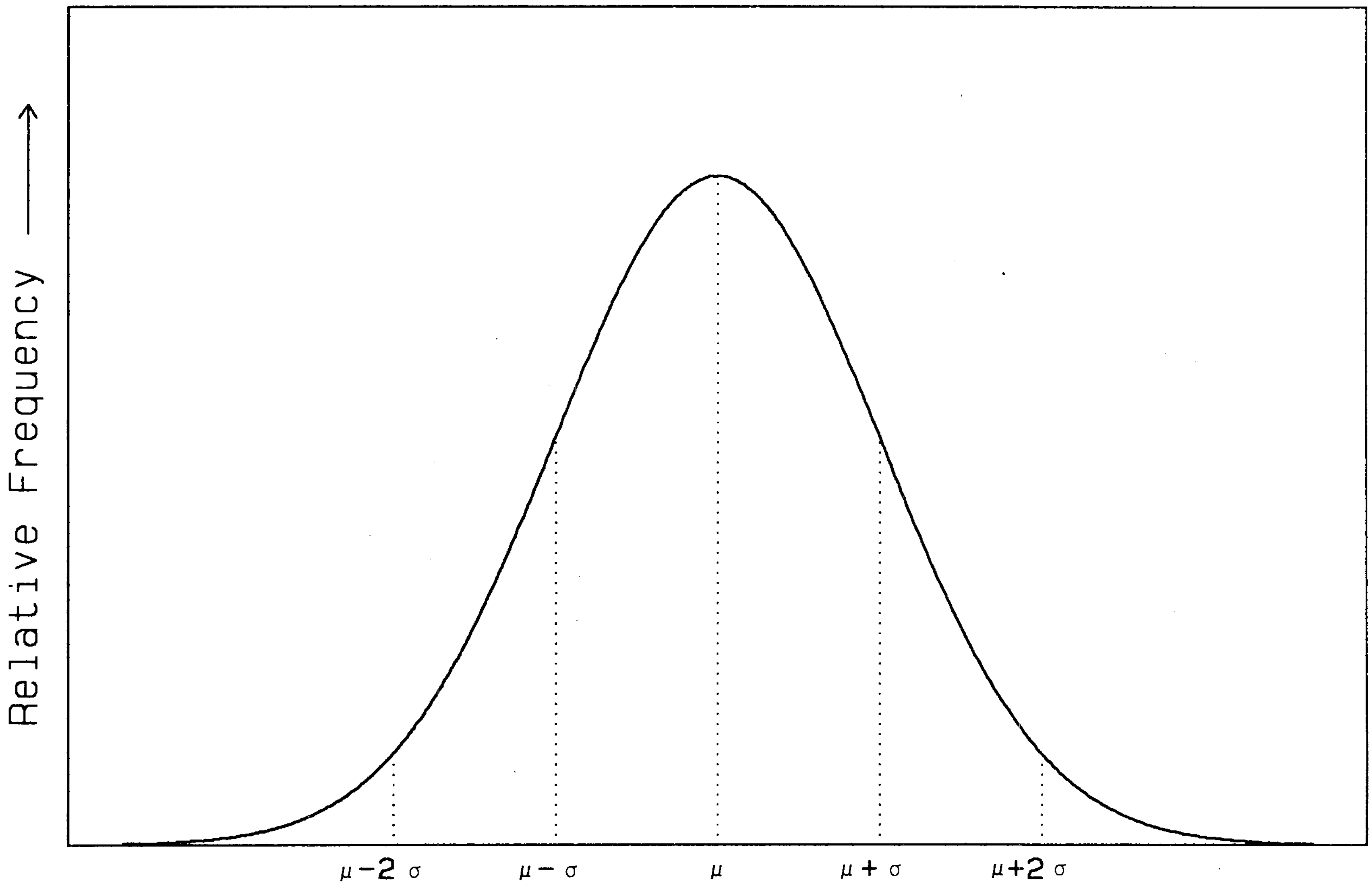

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Figure 2.3. Example of Normal Probability Distribution of Average Reservoir Temperature

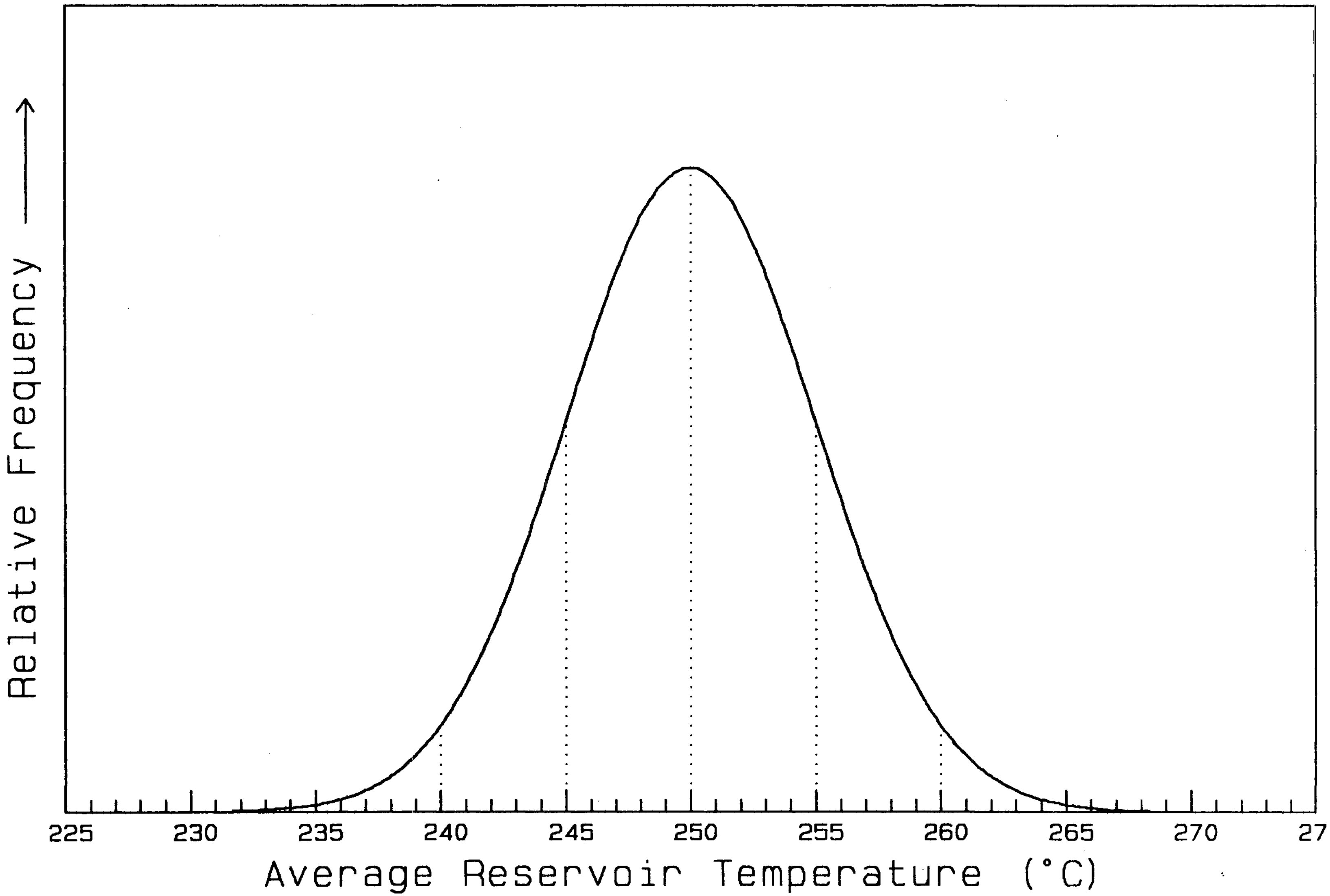

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Figure 2.4. The Lognormal Distribution

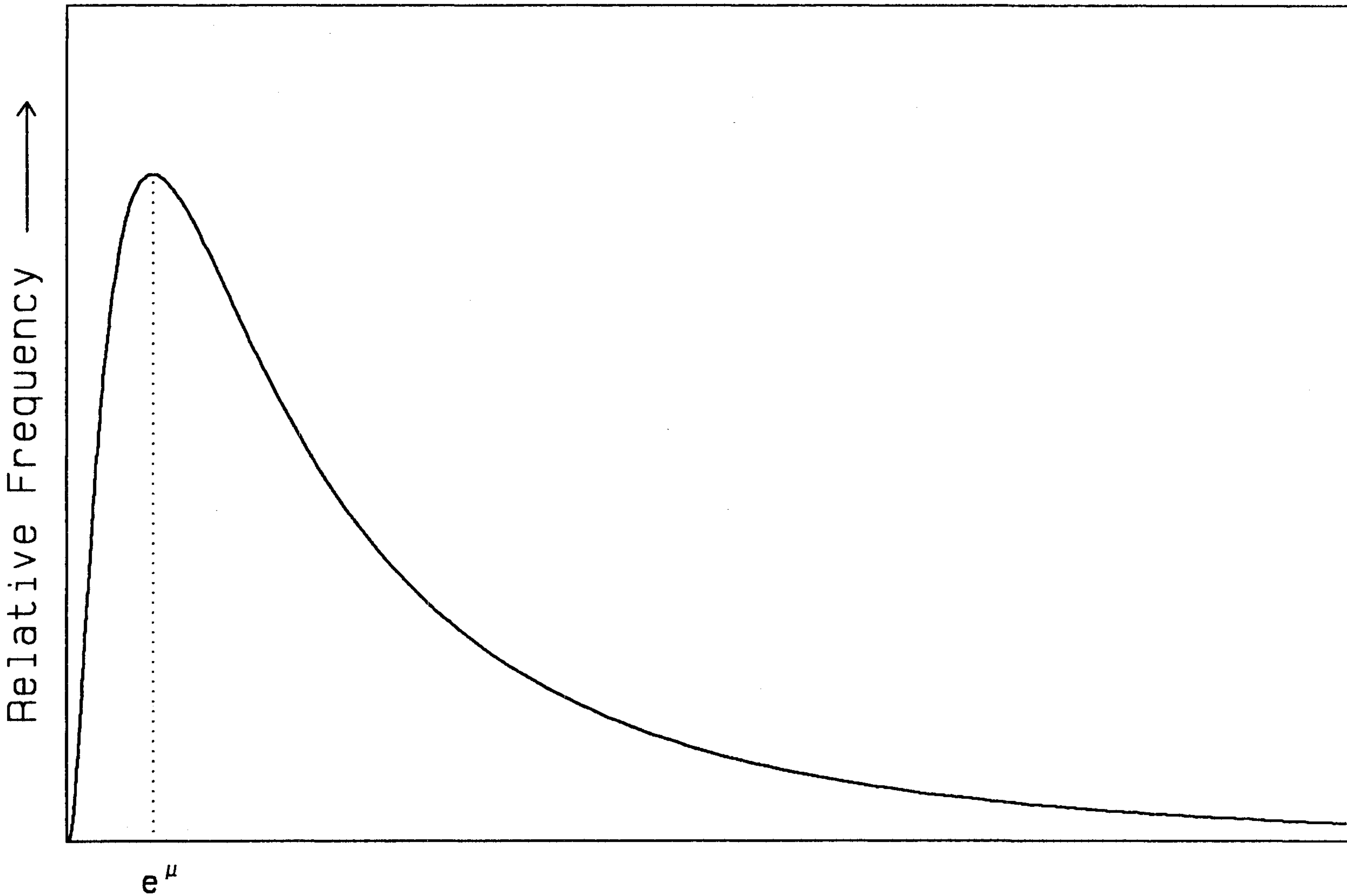

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Figure 2.5. Example of Lognormal Probability Distribution of Reservoir Thickness

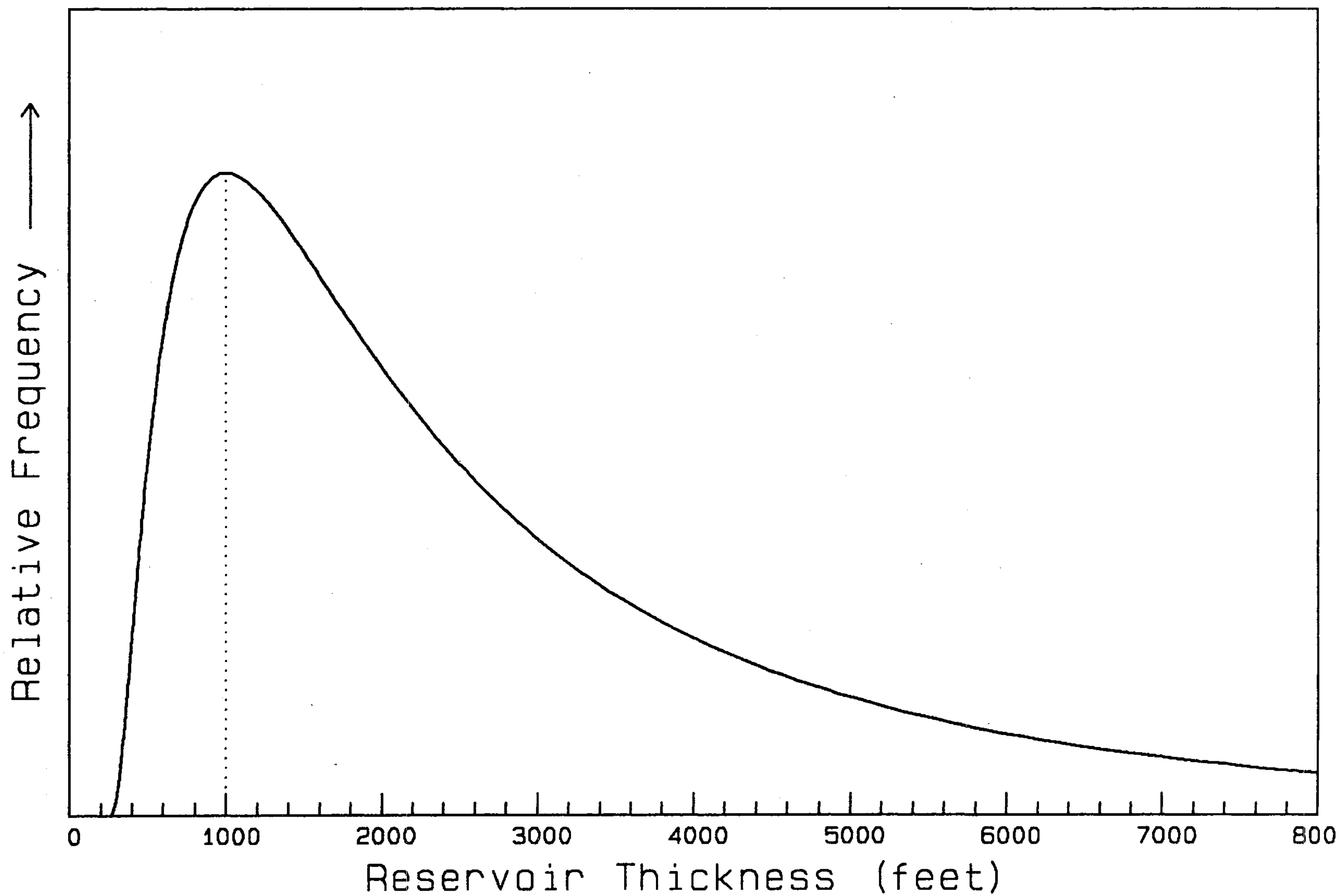

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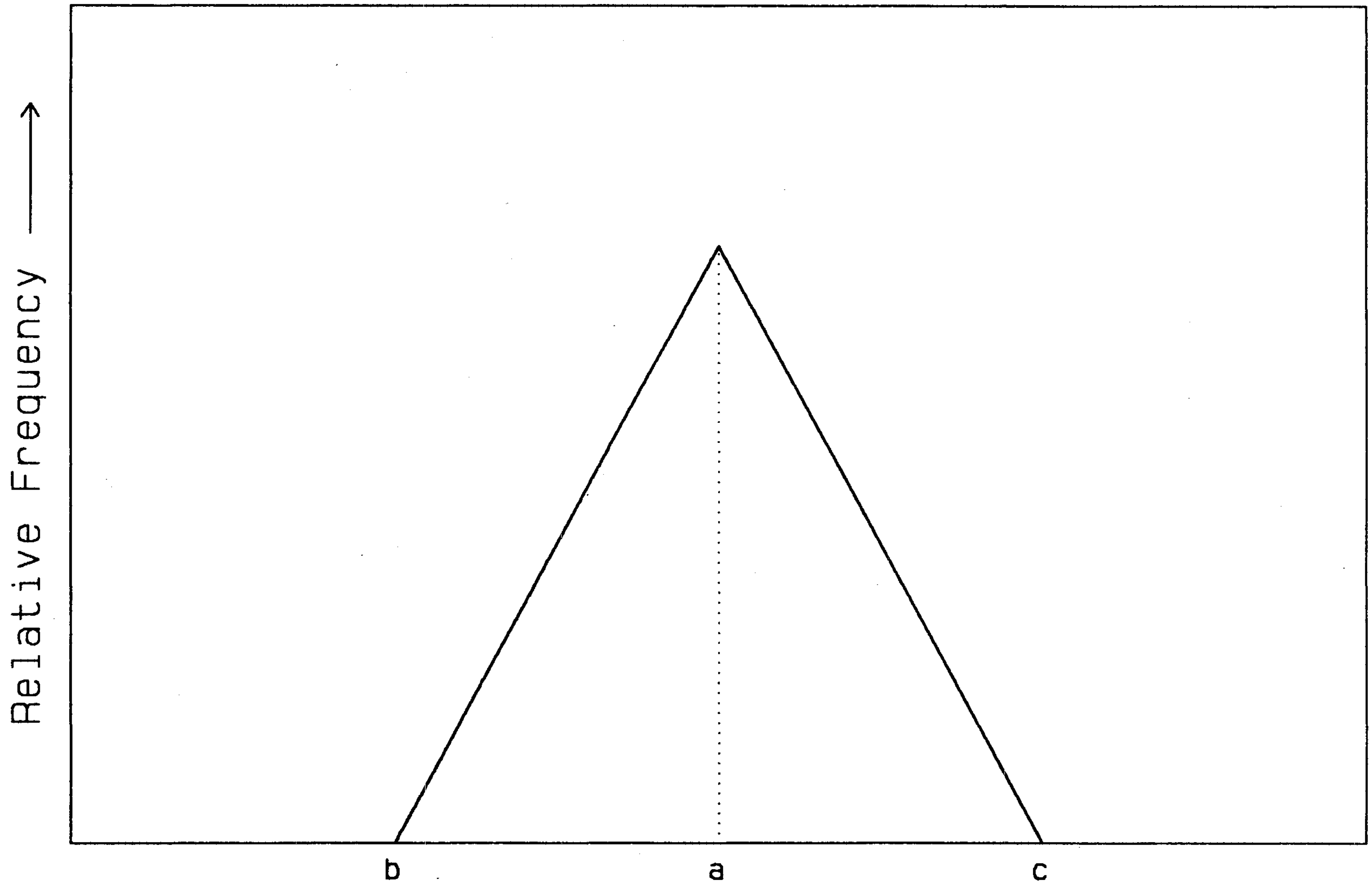
Figure 2.6. The Triangular Distribution



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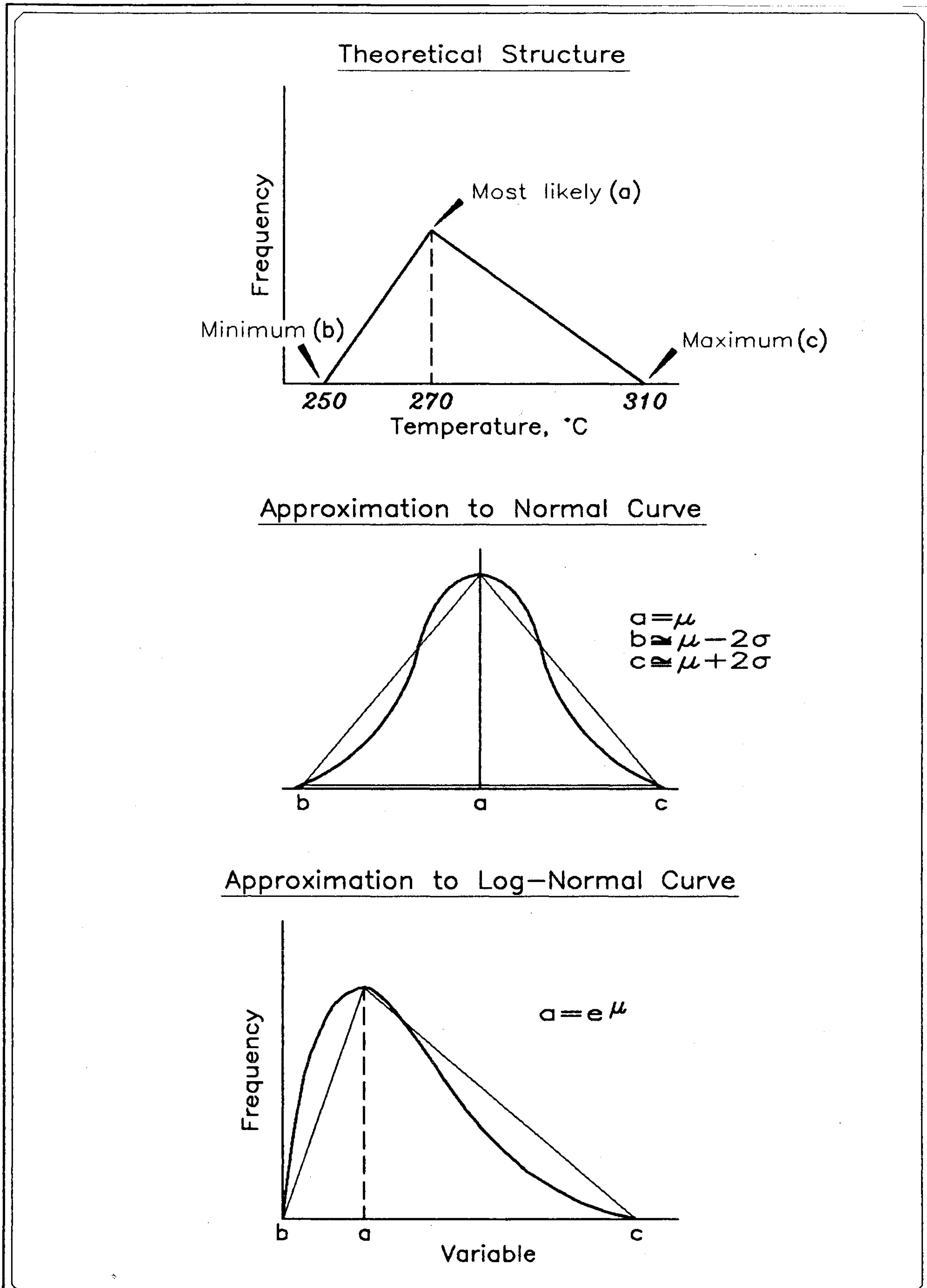

Figure 2.7: Triangular probability distributions.

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Figure 2.8. The Rectangular Distribution

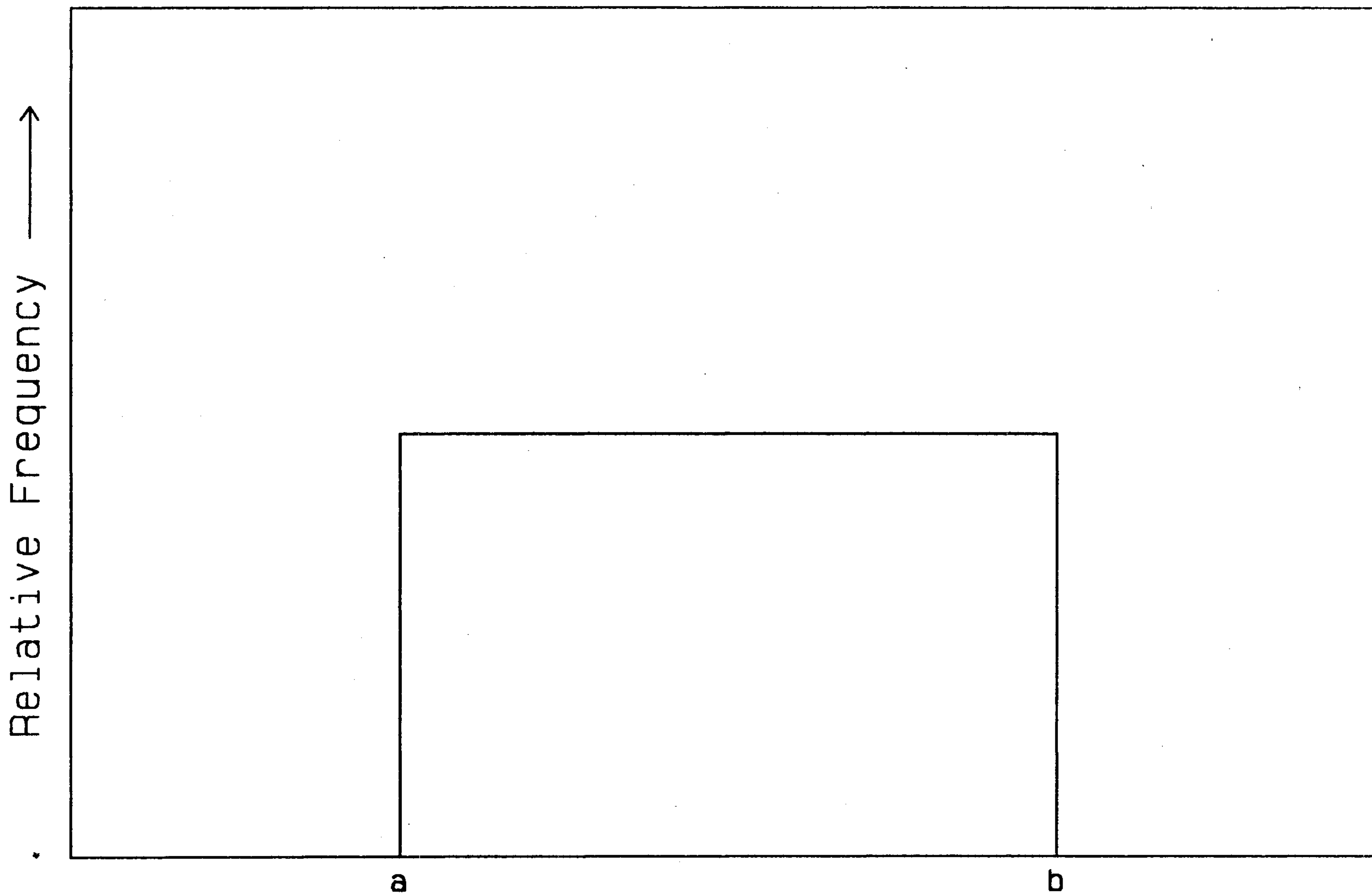

Figure 2.9. Example of Bimodal Probability Distribution of Reservoir Porosity

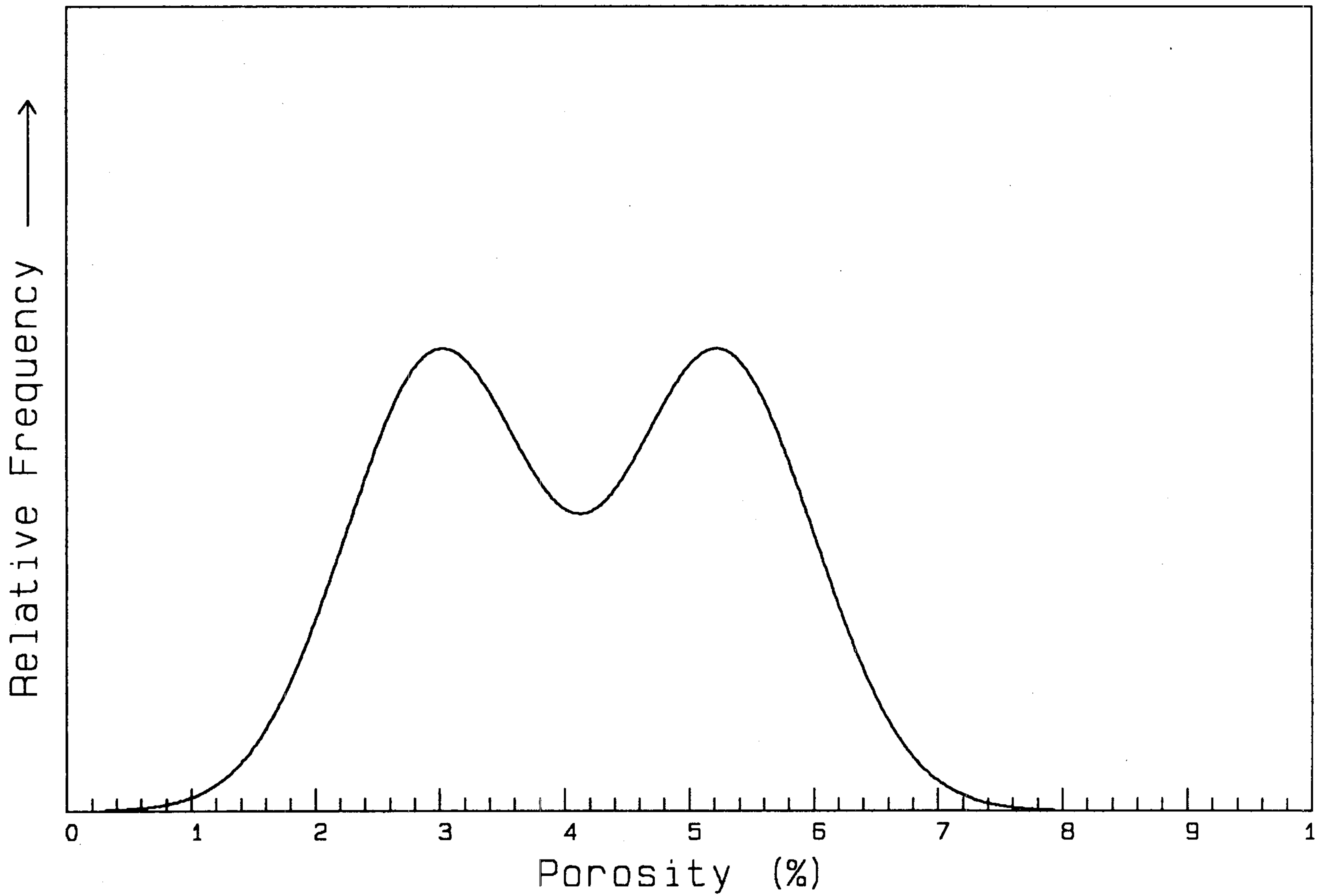

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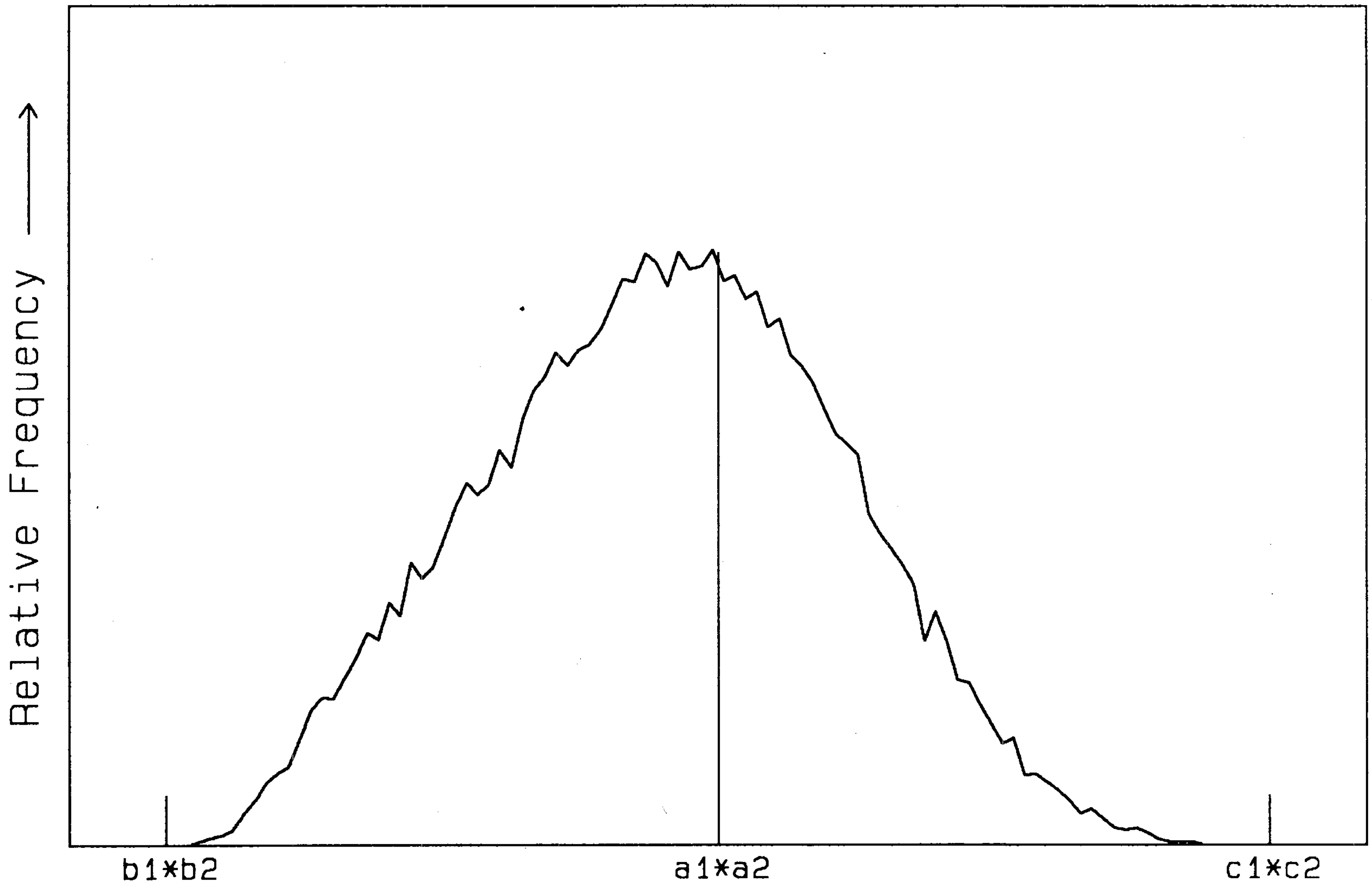
Figure 2.10. Example of Numerical Combination of Two Triangular Probability Distributions



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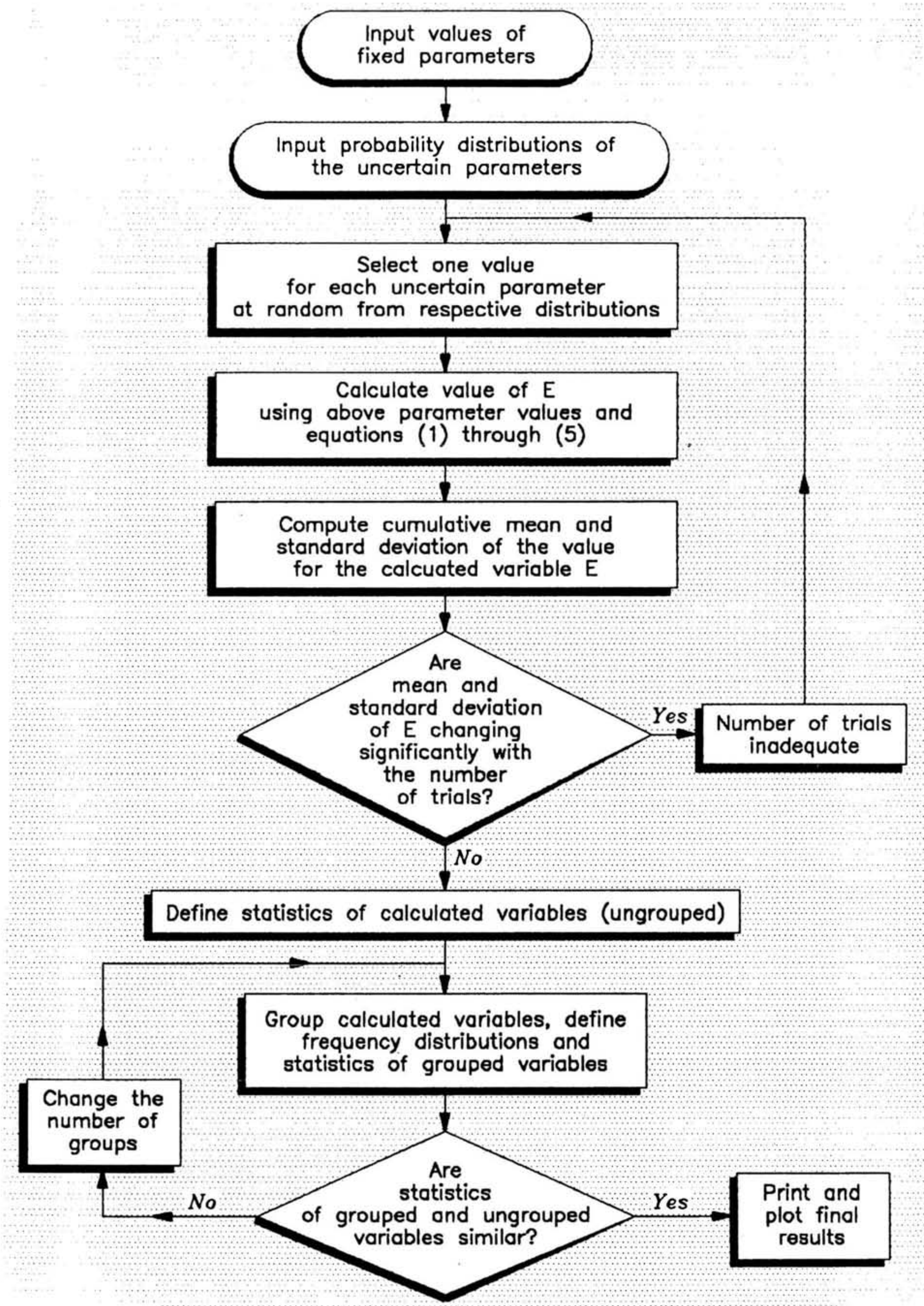

Figure 2.11: Schematic representation of the Monte Carlo simulation process

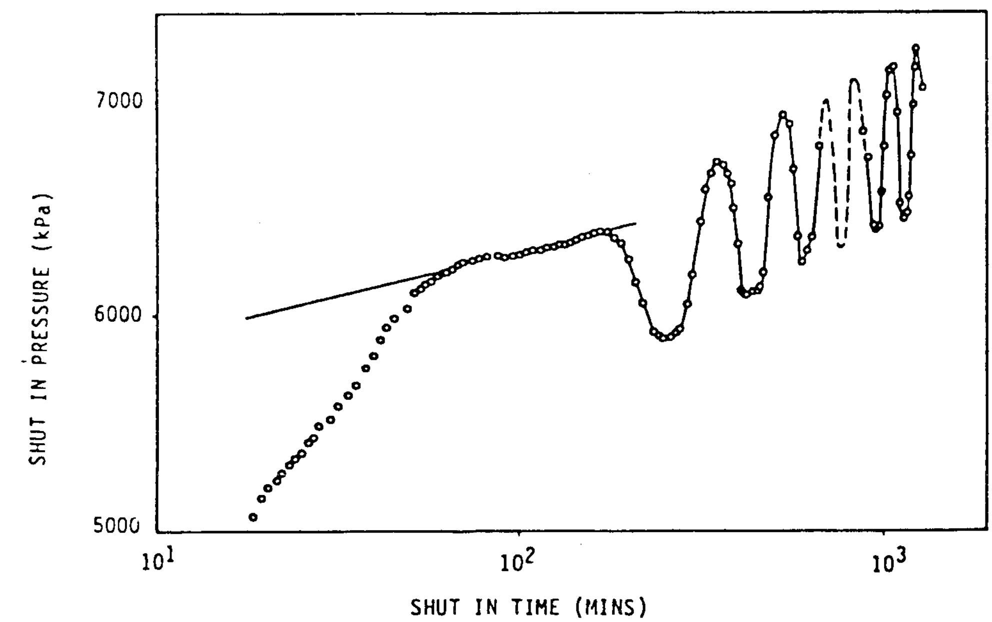

Figure 3.1: Example of MDH pressure buildup plot

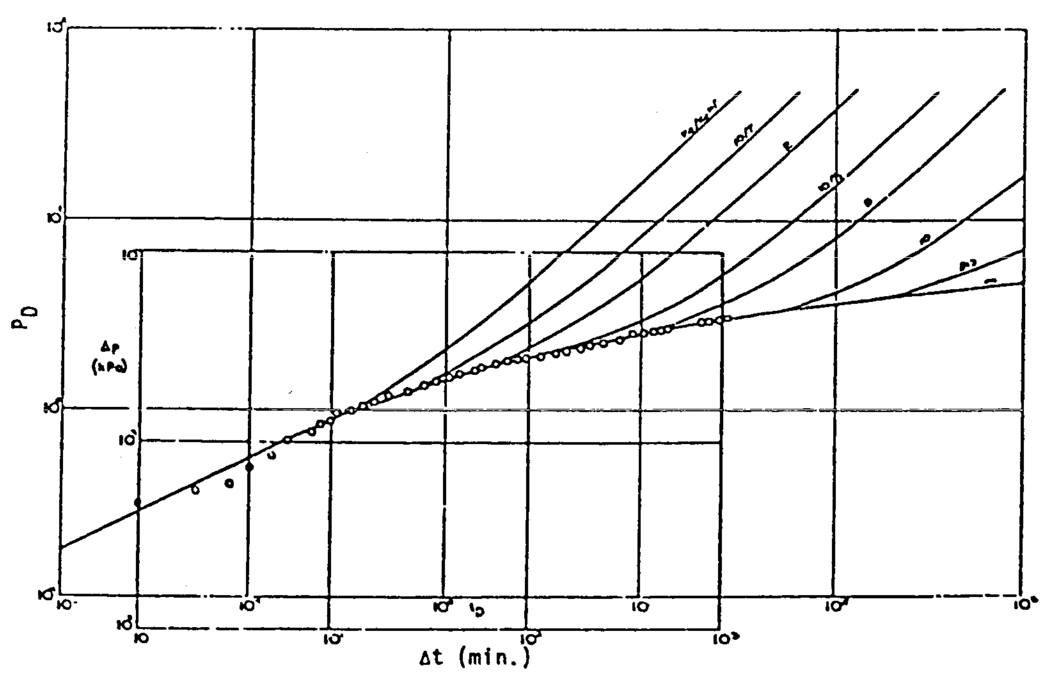

Figure 3.2: Analysis of drawdown data using type-curves

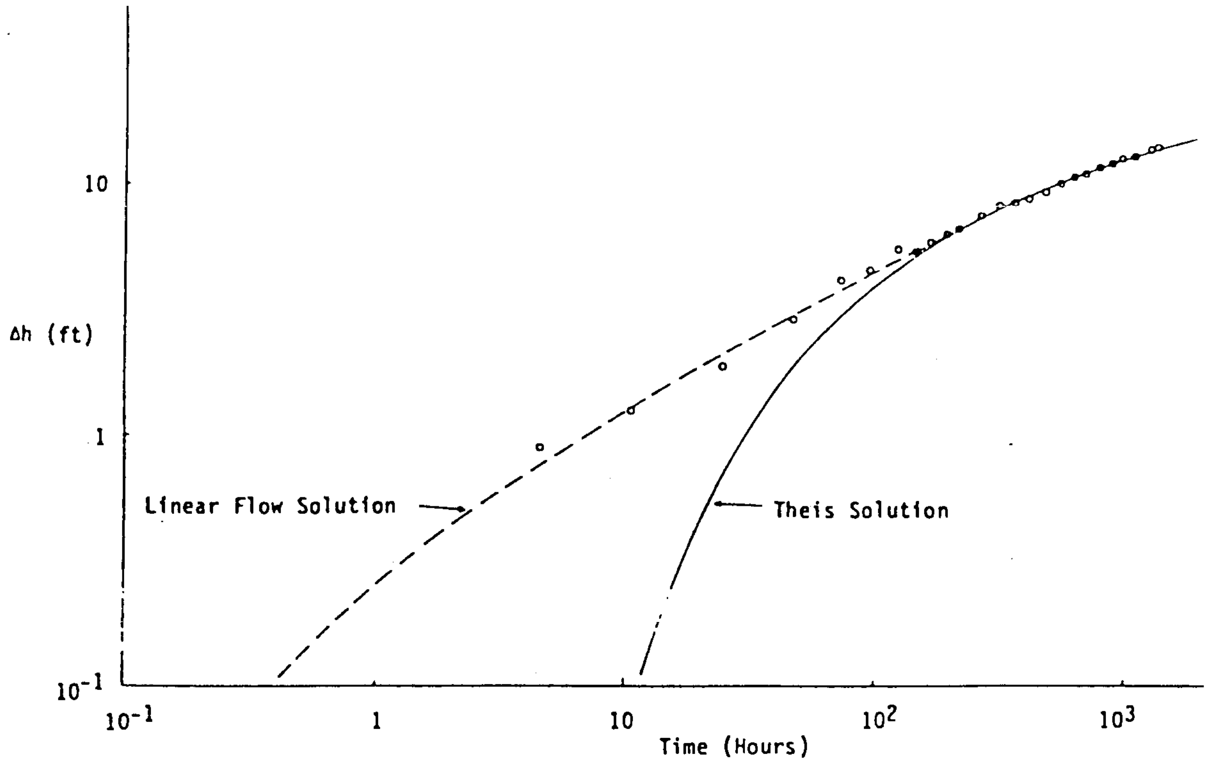

Figure 3.3: Type-curve match of interference data

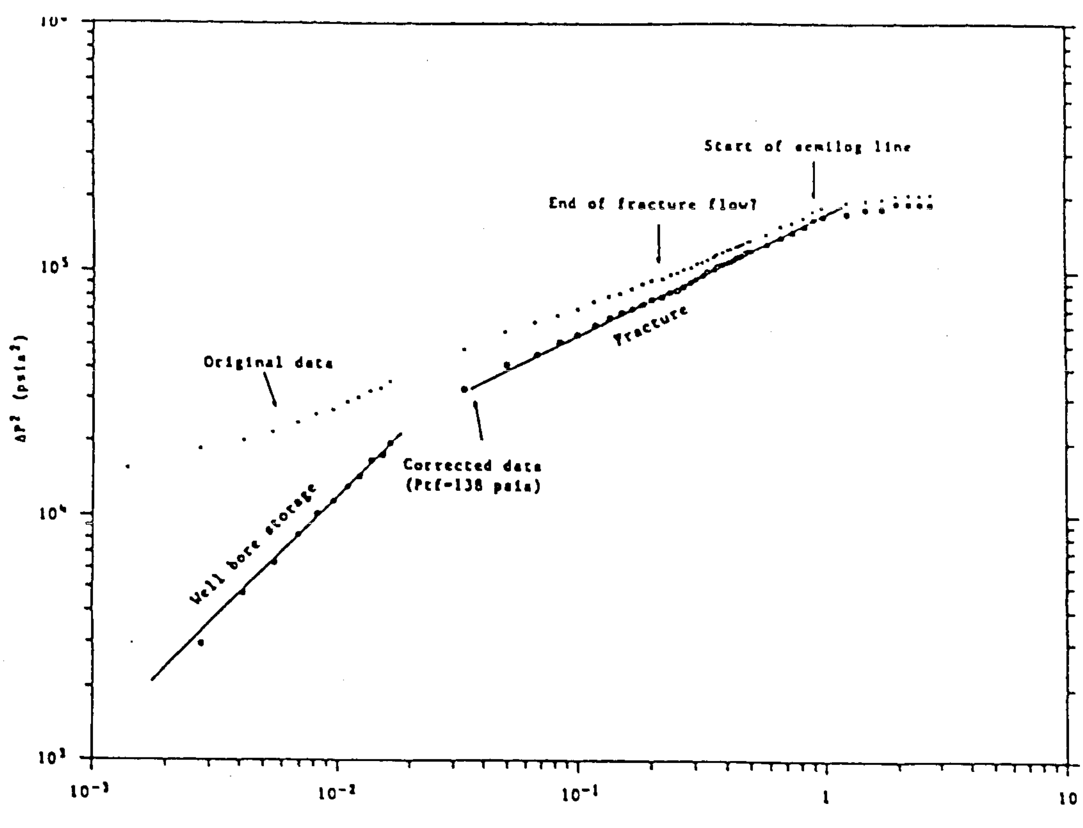

Figure 3.4: Log-log plot of buildup data from a well at The Geysers

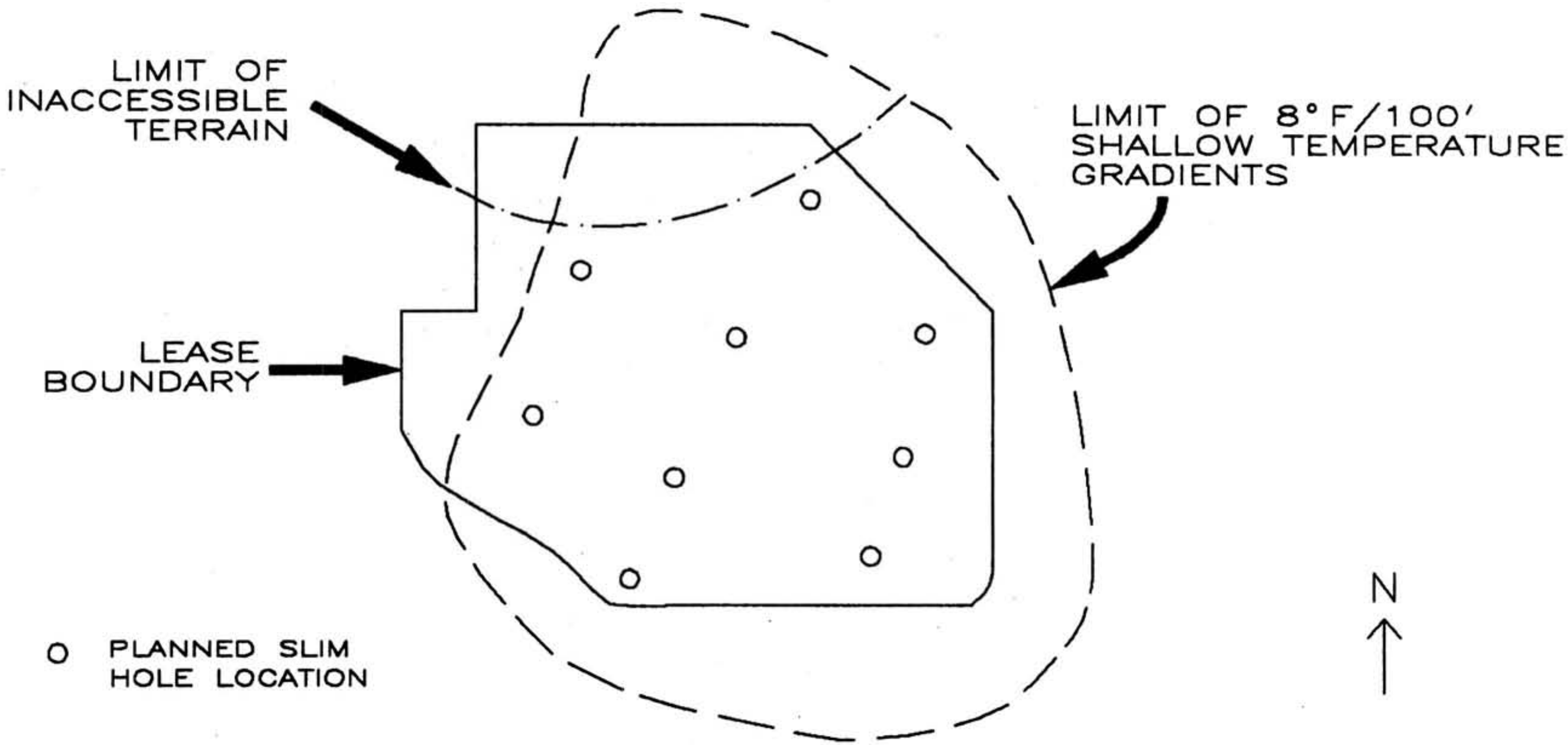

FIGURE 6.1. LEASE MAP AND SLIM HOLE DRILLING PLAN FOR HYPOTHETICAL GEOTHERMAL PROSPECT

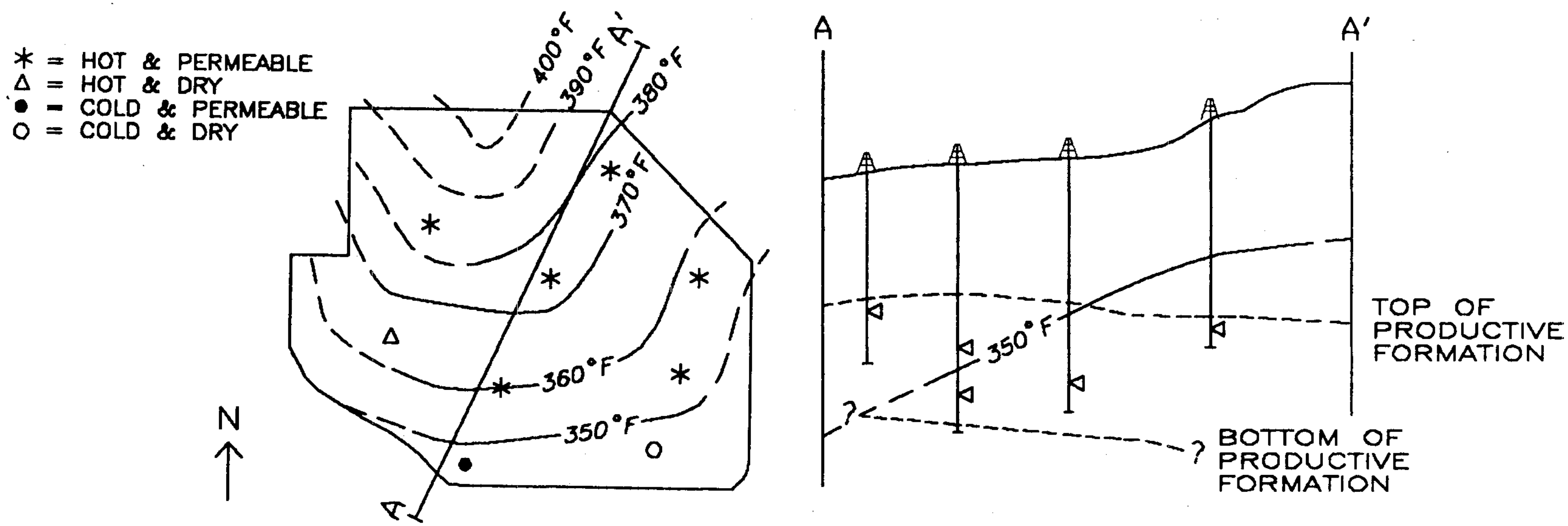

FIGURE 6.2. MAP AND CROSS SECTION OF DRILLING RESULTS IN HYPOTHETICAL PROSPECT

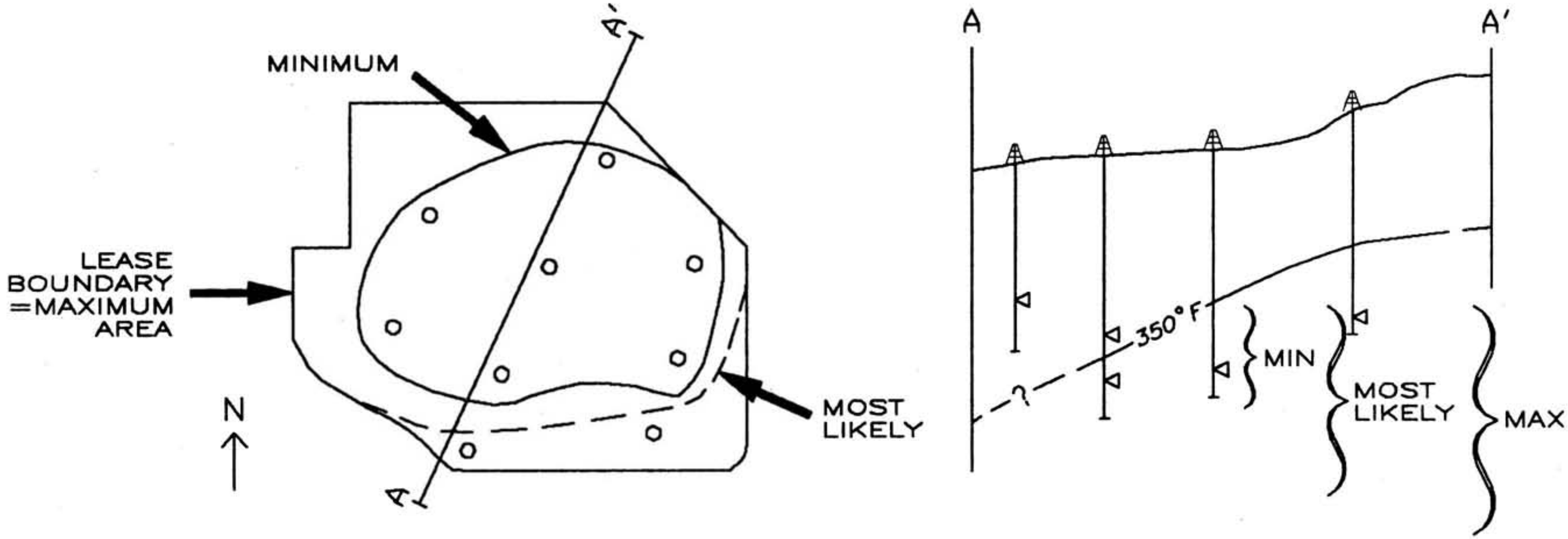

FIGURE 6.3. ESTIMATED MINIMUM, MAXIMUM AND MOST LIKELY RESERVOIR AREA AND THICKNESS

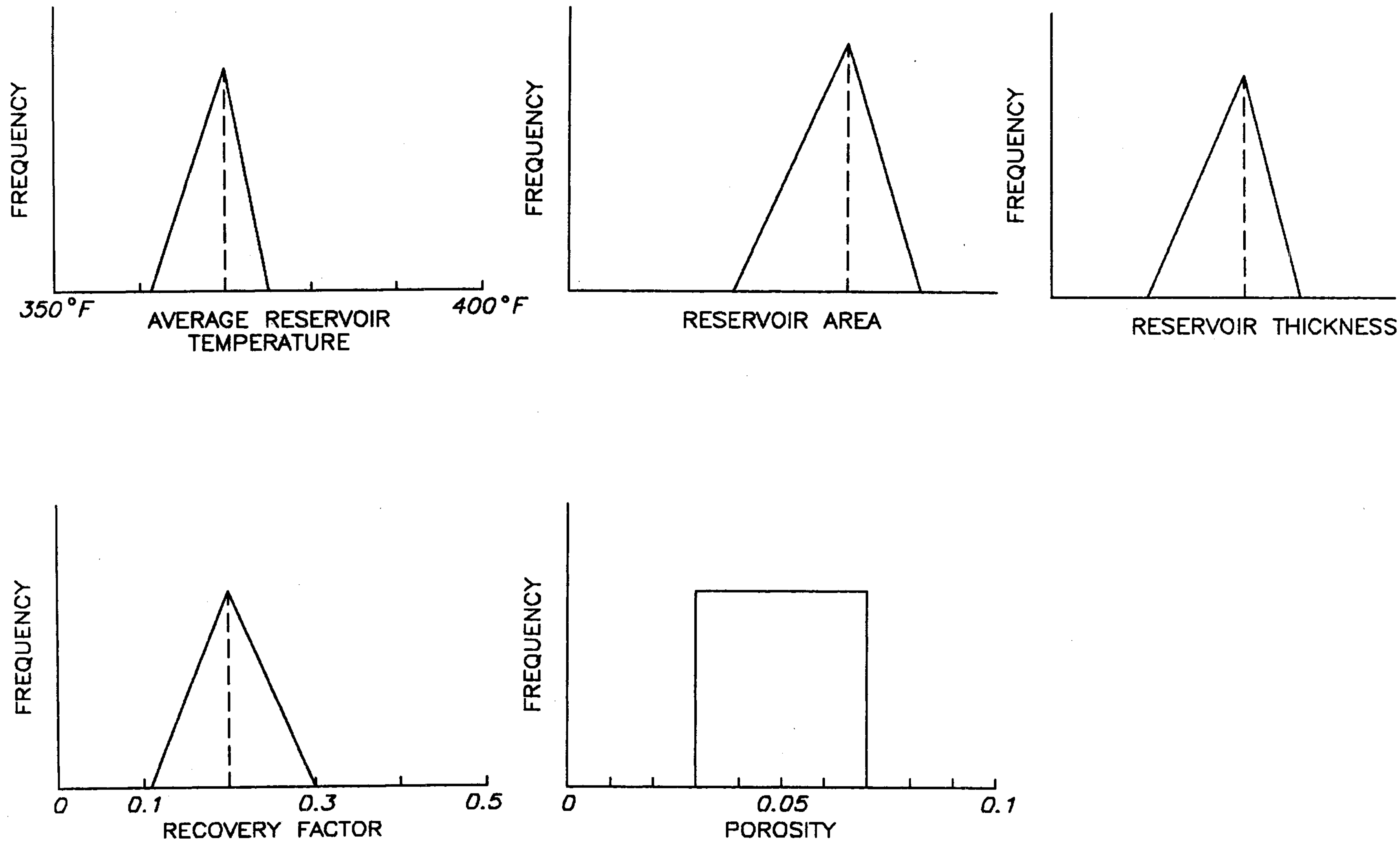

FIGURE 6.4. ESTIMATED PROBABILITY DISTRIBUTIONS USED IN ESTIMATE OF RECOVERABLE ENERGY RESERVES

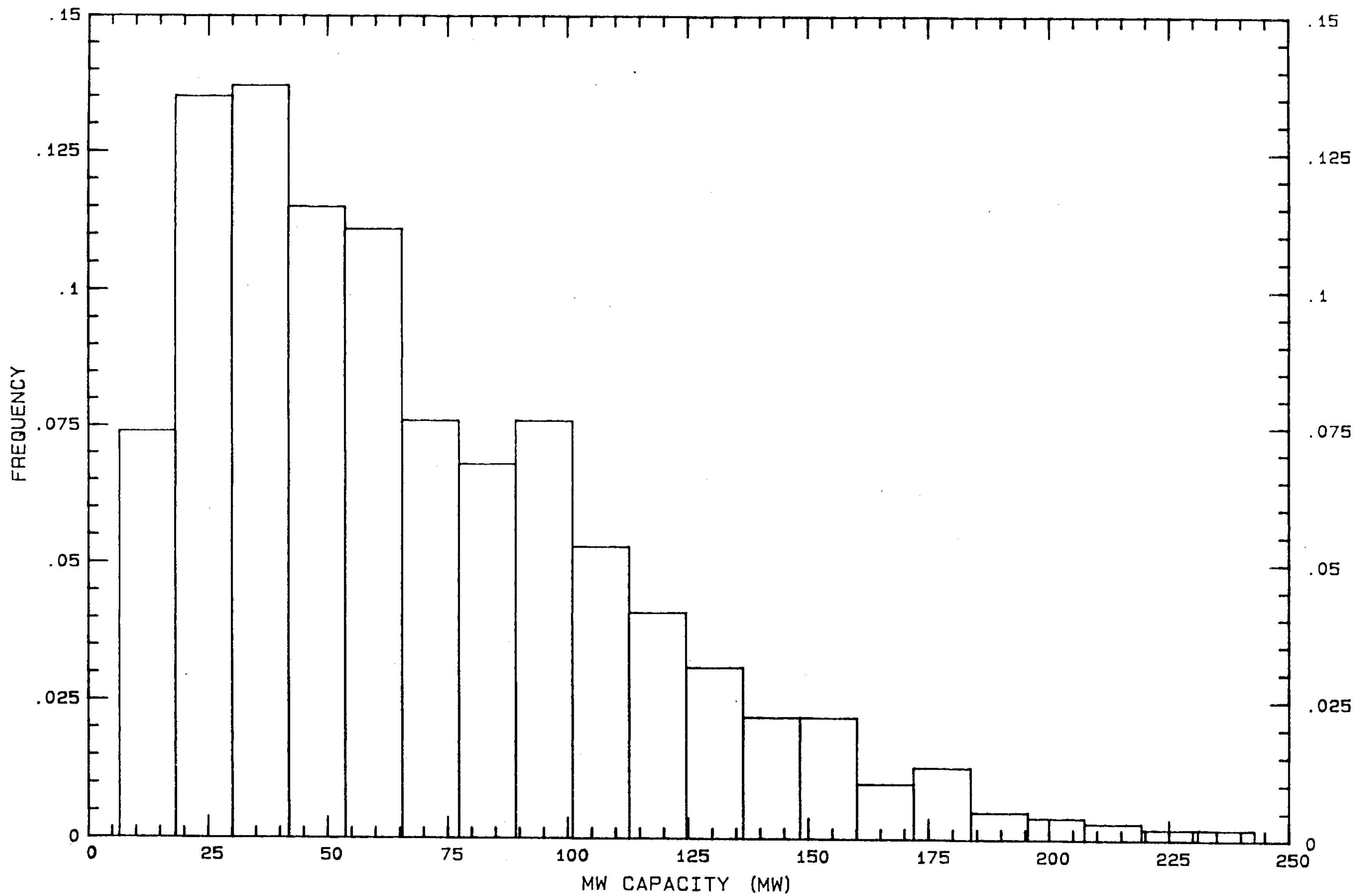

FIGURE 6.5: Sample histogram of MW capacity

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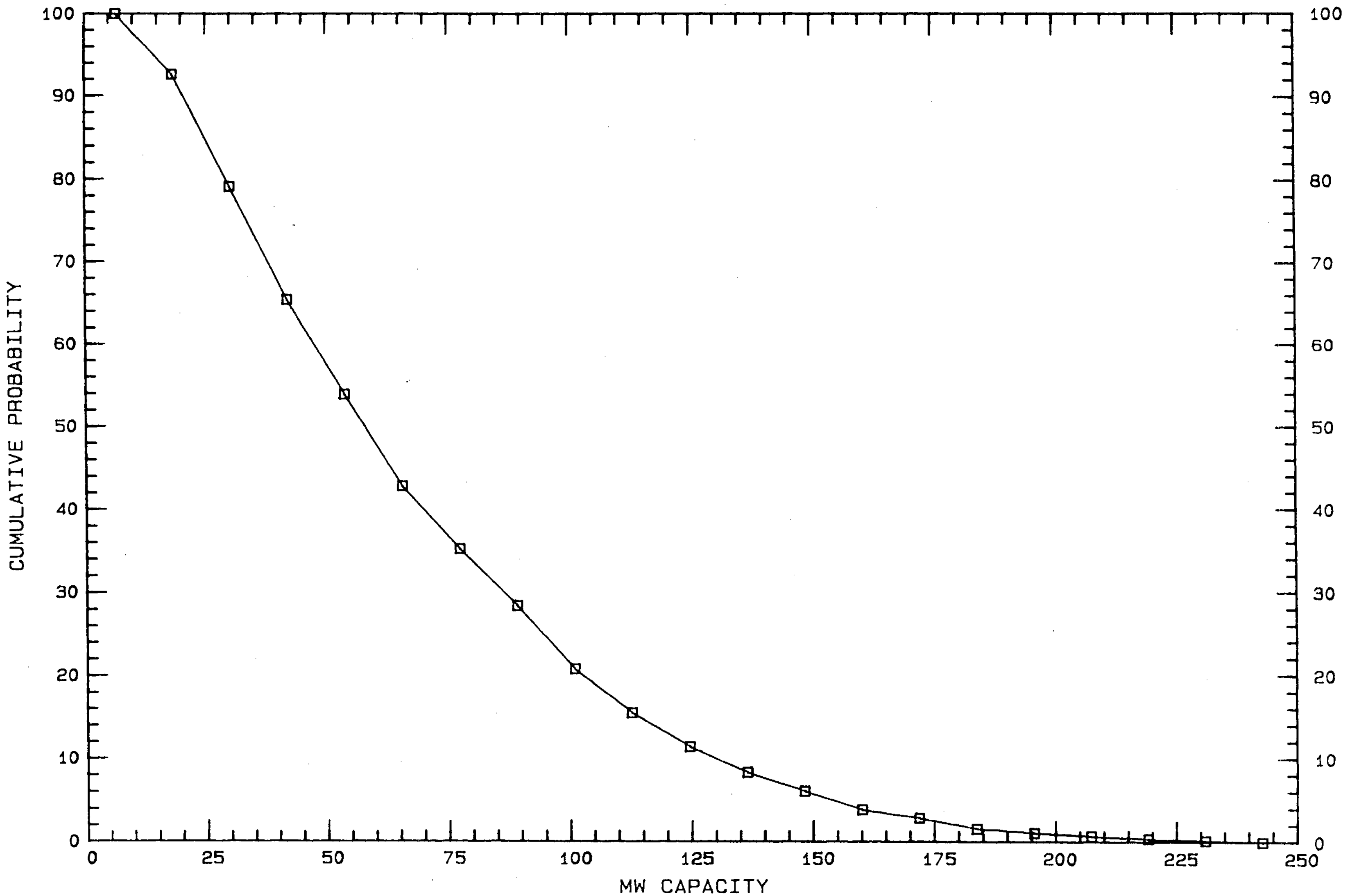

FIGURE 6.6: Sample cumulative probability plot of MW capacity

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